VENOCO, INC

2006 ANNUAL REPORT

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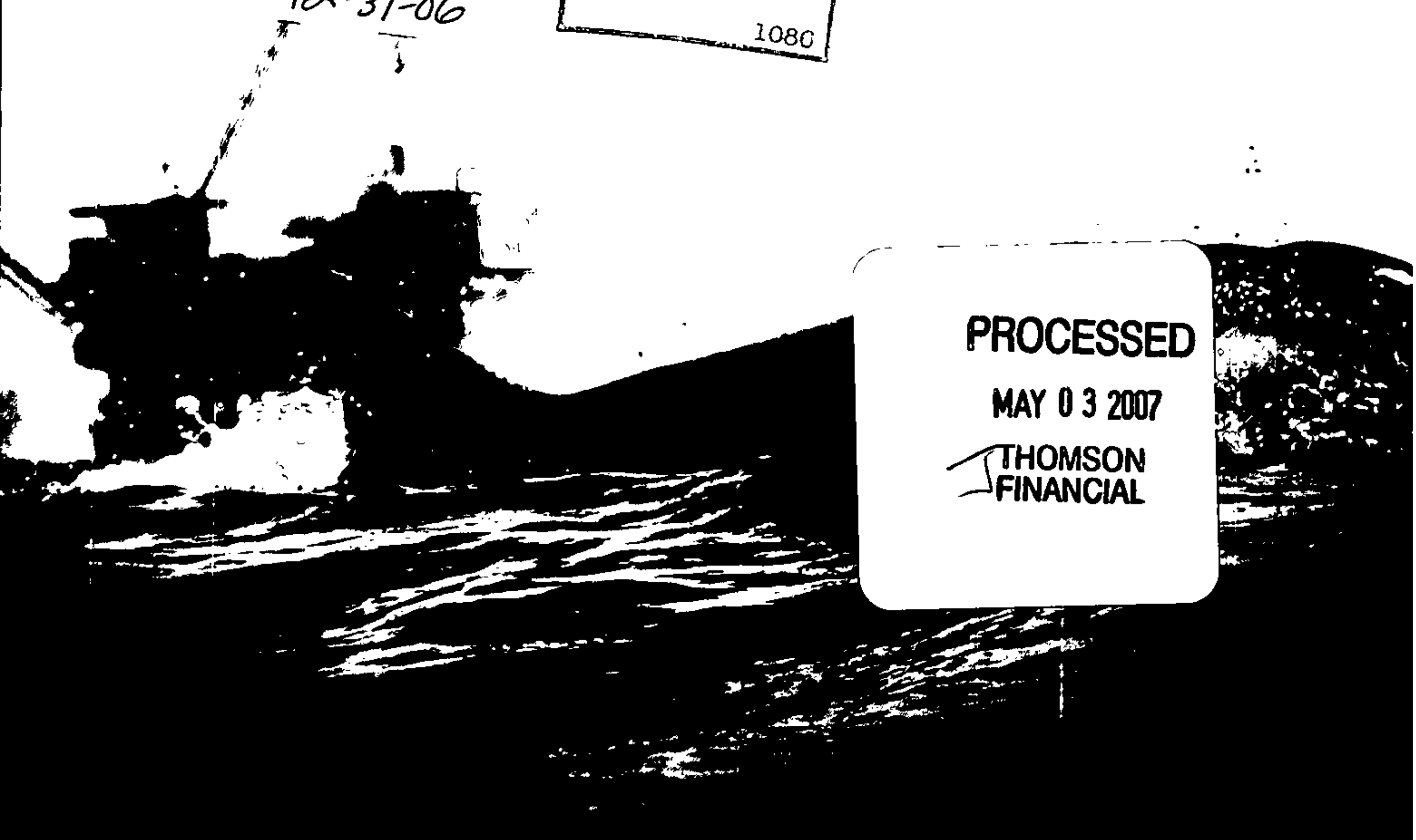

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ABOUT VENOCO, INC

Founded in 1992 with a few thousand dollars, Venoco has been an exciting and active place ever since. Now listed on the New York Stock Exchange—as VQ—Venoco demonstrates that hard work focused on the fundamentals of the oil and gas industry can bring success. Since acquiring its first property in 1994, Venoco has built a great acquisition track record with consistently low acquisition costs. We seek large, older, underdeveloped fields that frequently have operating or regulatory challenges. Our experienced technical and operational teams then implement the development strategies necessary to realize the potential value of these fields by increasing reserves and production. We've done it time and time again. Our compounded annual growth rate for production since 1994 is 44%—which speaks to how well we've been able to focus, plan and implement those strategies.

Our success as an independent oil and gas company comes as a surprise to some when they learn we have focused much of our efforts in California. California has a rich history of oil and gas production from some of the largest oil fields in the country. The perception is true—it can be very challenging to operate in California because California has some of the strictest environmental regulations in the world. However, where other operators see this regulatory maze as a barrier and burden, we see opportunities and a competitive advantage. Venoco is proud of its outstanding reputation in the communities in which it operates—both for being a good corporate citizen and for having a solid record of meeting California's high environmental standards.

WE HAVE BUILT A SOLID BASE OF ASSETS WITH LOW DECLINE, LONG-LIVED RESERVES. OUR BALANCE BETWEEN OIL AND GAS, ALONG WITH OUR CALIFORNIA AND TEXAS OPERATIONS, PROVIDES DIVERSITY IN BOTH PRODUCT AND GEOGRAPHY.

As coastal states with abundant natural accumulations of oil and gas, California and Texas have large economies that rely on domestic producers of energy. According to the U.S. Department of Energy's Energy Information Administration, California ranks third in proved crude oil reserves with 3.4 billion barrels, while Texas is first with 4.9 billion barrels. On the natural gas side, California is able to supply only 13% of its own natural gas demand, while being the second largest consuming state in the U.S.—a dynamic which creates generally attractive market conditions. Texas is the largest consuming state, but is also the state with the most active natural gas wells and natural gas reserves. What that means to Venoco is opportunity—both in finding oil and natural gas properties that fit our business model, as well as having ready markets for our production.

We believe Venoco is a very special company—a blend of quality operated properties, talented technical people and a management team that is highly invested in the company—controlling over 68% of the stock. As you read this annual report, our very first, we want you to know we are a group of hardworking, focused and experienced people who enjoy the challenges of the oil and gas industry and who will continue to build Venoco and add value for you, our stockholders.

CALIFORNIA OIL & GAS FACTS

1. 5 OF THE 12 LARGEST OIL FIELDS IN THE UNITED STATES ARE LOCATED IN CALIFORNIA
2. SANTA BARBARA CHANNEL AREA HAS SEVEN GIANT FIELDS, WHICH ARE AMONG THE LARGEST OF ALL FIELDS IN THE UNITED STATES
3. CALIFORNIA RANKS FOURTH AMONG THE LEADING OIL PRODUCING STATES
4. CALIFORNIA BEGAN COMMERCIALLY PRODUCING OIL AND GAS IN 187
5. 28 OF CALIFORNIA'S 58 COUNTIES PRODUCE OIL AND/OR GAS
6. CALIFORNIA HAS APPROXIMATELY 45,000 PRODUCING OIL AND NATURAL GAS WELLS
7. CALIFORNIA PRODUCES 920 MILLION CUBIC FEET PER DAY OF NATURAL GAS
8. CALIFORNIA NATURAL GAS PRODUCERS PROVIDE 13% OF THE TOTAL GAS CONSUMED IN CALIFORNIA
9. CALIFORNIA IS ESTIMATED TO HAVE AS MUCH AS 3.8 TRILLION CUBIC FEET OF NATURAL GAS IN ONSHORE RESERVES, AND AS MUCH AS 21 TRILLION CUBIC FEET IN OFFSHORE RESERVES
10. DIRECT AND INDIRECT EMPLOYMENT IN THE PETROLEUM EXPLORATION AND PRODUCTION INDUSTRY IN CALIFORNIA TOTALS APPROXIMATELY 75,000

BEST AVAILABLE COPY

LETTER TO STOCKHOLDERS

Every day the people of Venoco are living the values, behaviors and practices that make our organization one of the best-run oil and gas companies in the world. I say best-run because in 2006 our diligence and persistent hard work paid-off with several achievements, including:

- Consummating the $457 million TexCal Energy acquisition in March 2006, which added 31.4 MMBOE of proved reserves, and 400 new drilling opportunities in the prolific Sacramento Basin;
- Growing the TexCal proved reserves 35% and company-wide proved reserves by 85% to 87.9 MMBOE at December 31, 2006;
- Generating record net income of $24.0 million, or $0.69 per diluted share; and
- Completing a successful $157.5 million IPO of Venoco stock in November 2006.

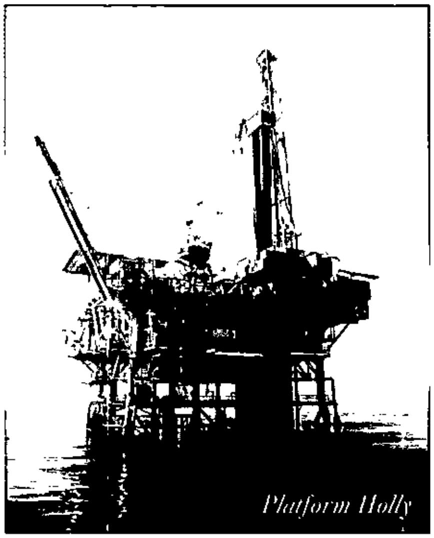
We are not the largest oil and gas company in the U.S., but we are one of the hardest working. As evidence that our hard work pays off, we like to highlight our 44% compounded annual growth in production since 1994. Exiting the year, our fourth quarter daily production was a company-record 18,147 BOEPD, giving our reserves a life of 13.3 years at current production rates. We've been able to achieve that kind of growth because of the high quality of our reserves, the majority of which are located in large, prolific fields with multiple productive horizons. Our 2006 finding and development cost was $14.45 per BOE. At the end of 2006, we had 650 identified drilling locations, representing a five-year inventory of drilling opportunities. Our year-end reserves of 87.9 MMBOE have a net present value, discounted at 10%, of $1.1 billion (see the enclosed 10-K for a reconciliation of this figure to a standardized measure of discounted future net cash flow).

Venoco is one of the largest producers of oil and natural gas in California. We have completed 39 producing property acquisitions since 1994, adding 142.4 MMBOE in proved reserves at an average price of $7.39 per BOE. Our acquisition of TexCal significantly increased our proved reserves, increased our base production rate by about 40% and added hundreds of drilling locations—primarily in California, but also in Texas. The acquisition diversified our reserves from mostly oil to 44% natural gas and from being entirely in California to having 26% of our reserves in Texas. We are also an active acquirer of premium acreage in California—we now have more than 222,430 net acres under lease in California, 64% of which are proved and producing.

Our strong operating performance has translated into financial success. We reported net income of $24.0 million (or $0.69 per diluted share) in 2006 up from $16.1 million (or $0.49 per diluted share) in 2005. We have a strong balance sheet to support our growth plans. We completed our Initial Public Offering on November 17, 2006 and raised $157.5 million, which was used to retire debt. We ended the year with $8.4 million in cash and $529.6 million in long-term debt, making our debt to enterprise value ratio 42%. We expect cash flow from operations to fund the majority of our 2007 capital expenditure program of approximately $230 million.

Although we're proud of our progress, we aren't resting. Venoco is poised to grow reserves, production and cash flow in 2007. We are high-grading our extensive drill site inventory to optimize production, capture reserves and prove up additional drilling opportunities. We are continuously evaluating opportunities to increase our strategic acreage positions in our areas of operation and to realize operational efficiencies and leverage our technical expertise.

At Venoco, we know that financial success is contingent upon being a good steward of our assets and the environment. The highest standards of social responsibility, ethical conduct and environmental



Platform Holly

sensitivity guide our actions. Our Health, Safety and Environmental (HS&E) policies and procedures are important elements of all phases of our operations. Our HS&E team ensures that we are actively pursuing environmental excellence in all our operations and minimizing the environmental impact of our operations every day. Venoco has won several HS&E awards, including Lease Maintenance awards from the California Division of Oil, Gas and Geothermal Resources.

To support and improve the communities where we live and work, Venoco's employees are actively involved as volunteers in many worthwhile charitable organizations and the company supports a number of community organizations through financial contributions. For these ongoing efforts, Venoco was recognized last year by *Oil and Gas Investor* magazine as CORPORATE CITIZEN OF THE YEAR.

WE BELIEVE IN CORPORATE RESPONSIBILITY AND IN BEING AWARE OF, AND RESPONSIVE TO, THE COMMUNITIES IN WHICH WE OPERATE. WE BELIEVE OUR INVOLVEMENT IN OUR COMMUNITIES WILL HAVE POSITIVE IMPACTS, NOT ONLY IN THE SHORT TERM, BUT WILL ALSO MAKE THESE COMMUNITIES BETTER PLACES TO LIVE FOR YEARS TO COME. WE'VE WORKED HARD TO CREATE THE KIND OF COMPANY IN WHICH PEOPLE ARE PROUD TO WORK AND INVEST.

Venoco is led by experienced management and operations teams with specific expertise in finding and producing oil and gas in California and Texas. Our team of geologists, drilling engineers, production engineers and other technical members gives us a competitive advantage in the areas where we operate. As the operator of 94% of our production, we are able to implement the operational and development plans these talented teams produce.

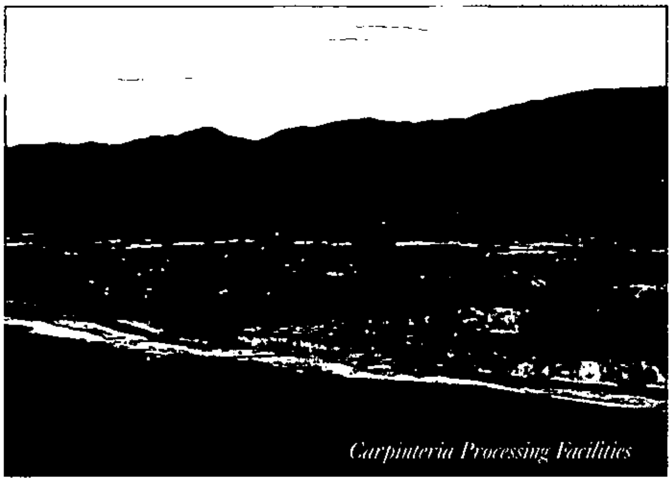
In combination, our assets, business strategy and use of new technological and environmental best practices will help us produce attractive returns for our stockholders. We plan to invest $130 million during 2007 for low-risk development drilling in the Sacramento Basin. Another $100 million will be invested in our properties in Texas and coastal California. We expect that our strategy will add production, reserves and cash flow resulting in higher net asset value and stockholder value. In 2006, we positioned Venoco to become a growth leader, and in 2007 I believe that we will deliver on that potential. I encourage you to get to know Venoco, as I'm sure you will like what you see.

Thank you,

Timothy Marquez
Chairman and Chief Executive Officer
April 30, 2007

OPERATIONS: OFFSHORE CALIFORNIA

Venoco's strengths include evaluating, buying and developing large underdeveloped oil and gas fields. California has a number of underdeveloped giant oil fields—maybe more than anywhere else in the world. In-state production for 2006 is estimated to be about 250 million barrels of oil by the Division of Oil, Gas & Geothermal Resources, which also estimates in-state recoverable oil reserves to be around 3 billion barrels. If California were a country, it would be the 27th largest producer in the world, between Egypt and Colombia. Operating in California makes perfect sense for us.

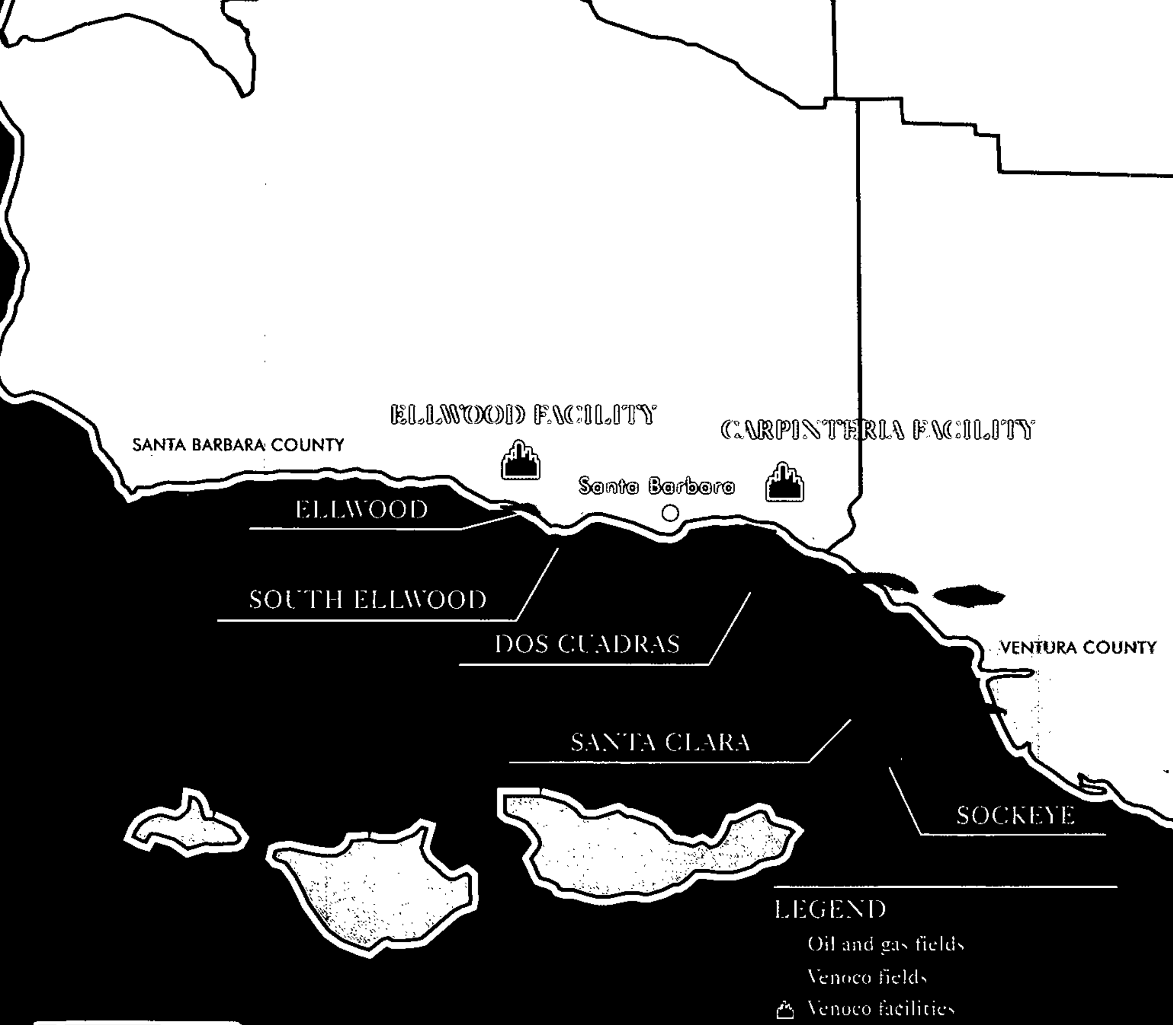


Carpinteria Processing Facilities

Our largest operated field is South Ellwood (100% WI, 83.3% NRI), a huge structure that is more than seven miles long and four miles wide. Net production from the field at year-end 2006 was 37 MBOEPD and comes from a single platform, Holly, which is located in the western portion of the field. When we purchased the field in 1997, we immediately undertook a series of geo-technical and engineering studies to obtain a more accurate assessment of the field's productive capacity. We are currently evaluating new drilling opportunities by interpreting 3-D seismic data, along with new low-energy 2-D survey data. In addition, we are pursuing the approvals necessary to extend our lease boundary and install a pipeline to replace the current barging operations. From studies and field work, we believe that the lease extension has substantial potential reserves.

Our Santa Clara Federal Unit (100% WI, 83.3% NRI), located ten miles offshore in the Santa Barbara Channel, exited 2006 producing 38 net MBOEPD from 19 wells. There are two fields, Sockeye and Santa Clara, which were developed from platforms Gail and Grace respectively. We are in the process of returning platform Grace to production, so presently all of the production in the unit is from platform Gail in the unit's largest field, Sockeye. Sockeye produces from five distinct zones—Monterey, Upper Topanga, Lower Topanga/Upper Sespe, Lower Sespe and Upper Juncal—and is estimated to have had 945 million barrels of original oil in place. Typical recovery factors for the Monterey zone, which is a prolific producing formation in the area, but thus far a small contributor in Sockeye, are low—between and 1% and 2.5%. New technology and techniques that can increase that factor can have a significant impact. Our technical staff drilled three successful infill development wells in the Sockeye Field in 2006. They have also drilled an exploration well and installed and managed a large waterflood project to increase the recoverable volumes from the field.

In 2007 we expect to invest $55 million in coastal California to drill between two and six new wells and install other equipment in order to increase daily production rates.



VENOCO HAS A HIGHLY PRODUCTIVE SET OF OIL ASSETS IN THE CALIFORNIA COASTAL COUNTIES OF SANTA BARBARA, VENTURA AND LOS ANGELES: 3 OPERATED PLATFORMS AND 3 NON-OPERATED PLATFORMS, PROVED RESERVES OF 37.4 MMBOE, PRODUCTION OF NEARLY 10,000 NET BARRELS OF OIL EQUIVALENT PER DAY, AND TWO OIL AND NATURAL GAS PROCESSING FACILITIES. BESIDES PROVED RESERVES, OUR EXISTING FIELDS HAVE PROBABLE AND POSSIBLE RESERVES. OUR OPERATIONS MANAGERS—WHO AVERAGE MORE THAN 23 YEARS OF EXPERIENCE—AND OUR EXPERIENCED OPERATIONS STAFF—MANY OF WHOM HAVE WORKED THEIR ENTIRE CAREERS ON THESE PLATFORMS—PROVIDE US THE SKILL TO EFFICIENTLY PRODUCE AND EXPAND OUR RESERVES.

OPERATIONS: SACRAMENTO BASIN

We're the largest natural gas producer in the Sacramento (Sac) Basin, controlling more than 222,430 gross acres, and, during the fourth quarter of 2006, averaging net production of approximately 40 MMCFE per day from 350 gross wells. Exiting December 31, 2006, we operated 100% of the 167 BCFE (27.9 MMBOE) of total proved reserves. We own an extensive geologic and engineering database, with well data on more than 10,000 wells, and a seismic library of 986 square miles of 3-D seismic and approximately 20,000 linear miles of 2-D.

The Sac Basin provides Venoco with an excellent platform for production and reserves growth because it offers a large inventory of underdeveloped acreage with multiple, low-risk development locations. In addition, the basin offers some deeper, moderate-risk drilling prospects to fuel future growth.

IN 2006, WE DRILLED 60 WELLS AND COMPLETED 34 WORKOVERS IN THE SAC BASIN. WE INCREASED DAILY PRODUCTION FROM DECEMBER 2005 TO DECEMBER 2006 IN THE BASIN BY 85% AND INCREASED THE COMPANY'S PROVED RESERVES IN THE BASIN BY 210%. IN 2007, WE PLAN TO INVEST AGGRESSIVELY TO FURTHER INCREASE PRODUCTION, RESERVES AND CASH FLOW.

The following discussion includes some of our 2006 drilling highlights as well as plans for 2007.

Our largest assets in the basin are the Greater Grimes and Willows Fields (71% average WI), where we operate 298 producing wells that delivered approximately 37 MMCF net per day in December 2006. Our estimated reserves here are 152.7 BCF. In 2006, we drilled 58 wells. For 2007, our aggressive drilling program in the Sac Basin consists of running six rigs to drill over 120 new wells. We will also perform additional recompletions into new productive zones in existing wells. We are continuously evaluating new opportunities for strategically acquiring acreage that improves our competitive position and operational efficiencies.

We have interests in other fields in the Sacramento Basin, located in Solano, Contra Costa, San Joaquin and Colusa Counties. We operate each of these fields and have working interests ranging from 42% to 100%. We drilled two wells in 2006, giving us 52 active producing wells in these fields producing 4.7 MMCF per day in December 2006. We believe that these areas have exploration and development opportunities similar to those in the Greater Grimes and Willows Fields.

In the Sac Basin, we've identified 547 drilling locations, representing a four to five year drilling inventory as well as 400 recompletion opportunities. Located in a temperate climate, we conduct drilling operations year-round. We currently drill wells on 40-acre spacing and are evaluating the potential to downspace to 20-acres.

ON MARCH 31, 2006, WE COMPLETED THE LARGEST ACQU... HISTORY, PURCHASING TEXCAL ENERGY, LLC, WHICH HAD A SIGNIFICANT NUMBER OF PRODUCING PROPERTIES, UNDEVELOPED LAND AND 31.4 MMBOE OF PROVED RESERVES.

Rising from the rice fields on the valley floor, Sutter Buttes are a familiar land mark in the Grimes area.

The acquisition makes Venoco one of the largest operators in the Sac Basin in terms of reserve drilling locations and production. The acquisition added 132 wells in the basin that were produci 17.7 MMCF per day at the time of the acquisition. The acquisition is of strategic importance Venoco because the acquired properties are contiguous to our Grimes area and therefore of significant operating synergies. The acquisition includes primarily operated wells with high worki interests as well as a large, near-immediate drilling prospect inventory. With the significant natu gas assets acquired, as of December 31, 2006 natural gas represents 43.6% of our total proved reser and 43.4% of our daily production.

OPERATIONS: TEXAS

Venoco owns an 89% interest in the West Hastings Unit and a 100% interest in the East Hastings and Hastings fields, which together comprise a giant oil field complex in South Texas. Since oil was discovered here in 1934, more than 637 million barrels have been produced. The complex's production peaked in 1984, but since has declined. In March 2006, the net production average was 1,538 BOE per day from 90 wells. In April 2006, Venoco implemented a workover program that has generated an increase in the net production levels to 2,434 BOE per day in December 2006, an increase of 58%. Turning around a declining complex is a perfect demonstration of Venoco's operating strengths. During 2006, our recompletion and workover program generated positive results. We restored wells to production, installed new production equipment and completed over 140 workovers. These efforts increased proved reserves by 186%.

Although the complex is in an advanced stage of primary depletion, Venoco has the expertise to maintain and increase the complex's present production through installation of electric submersible pumps as well as redesign and implementation of a water flood. Late in 2006, Venoco entered into an option agreement to sell the Hastings complex to a major operator of CO2 floods. The operator will pay Venoco $50 million over 3 years for the option to acquire the complex in November 2008 or 2009. If the option is exercised, the operator will purchase the complex for 100% of the then present value of Venoco's proven reserves and invest at least $178.7 million over a five year period to implement the CO2 flood. Venoco retains an overriding royalty interest of 2% and receives a reversionary working interest of 22.3% following payout. As of the end of 2006, we had no reserves booked related to the CO2 flood.

ONSHORE TEXAS GULF COAST IS THE MOST HEAVILY DRILLED AREA IN THE U.S. ACCORDING TO THE UNITED STATES GEOLOGIC SURVEY, THE REGION HAS HAD MORE THAN 567,000 WELLS DRILLED, AND 60% WERE SUCCESSFUL. EXPLORATION HAS LED TO THE DISCOVERY OF 2,518 SIGNIFICANT FIELDS, COMPRISING 3,883 SIGNIFICANT OIL AND GAS RESERVOIRS. THE SALT DOME BASINS IN EAST TEXAS ARE THE OLDEST IN THE STATE, HAVING BEEN A PART OF SUCH SIGNIFICANT DISCOVERIES IN THE EARLY 1900s AS SPINDLETOP, SARATOGA DOME AND SOUR LAKE DOME. OF THE FIELDS DISCOVERED IN THE 1930s, THE MOST PROLIFIC IN CUMULATIVE PRODUCTION WERE WEST HASTINGS FRIO (534 MMBOE), WEBSTER UPPER FRIO (528 MMBOE), THOMPSON FRIO (325 MMBOE), ANAHUAC MAIN FRIO (227 MMBOE) AND EAST HASTINGS UPPER FRIO (112 MMBOE).

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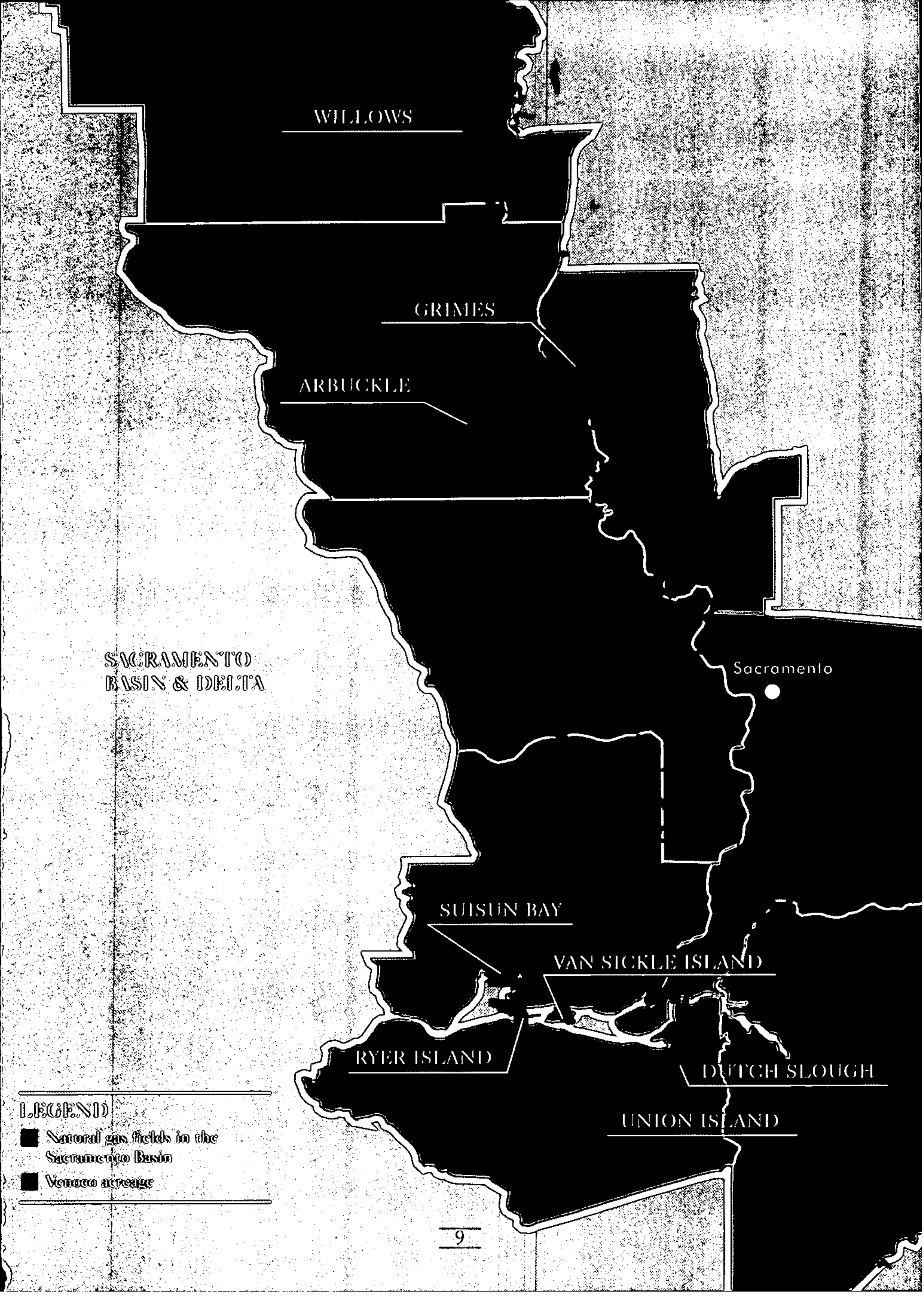
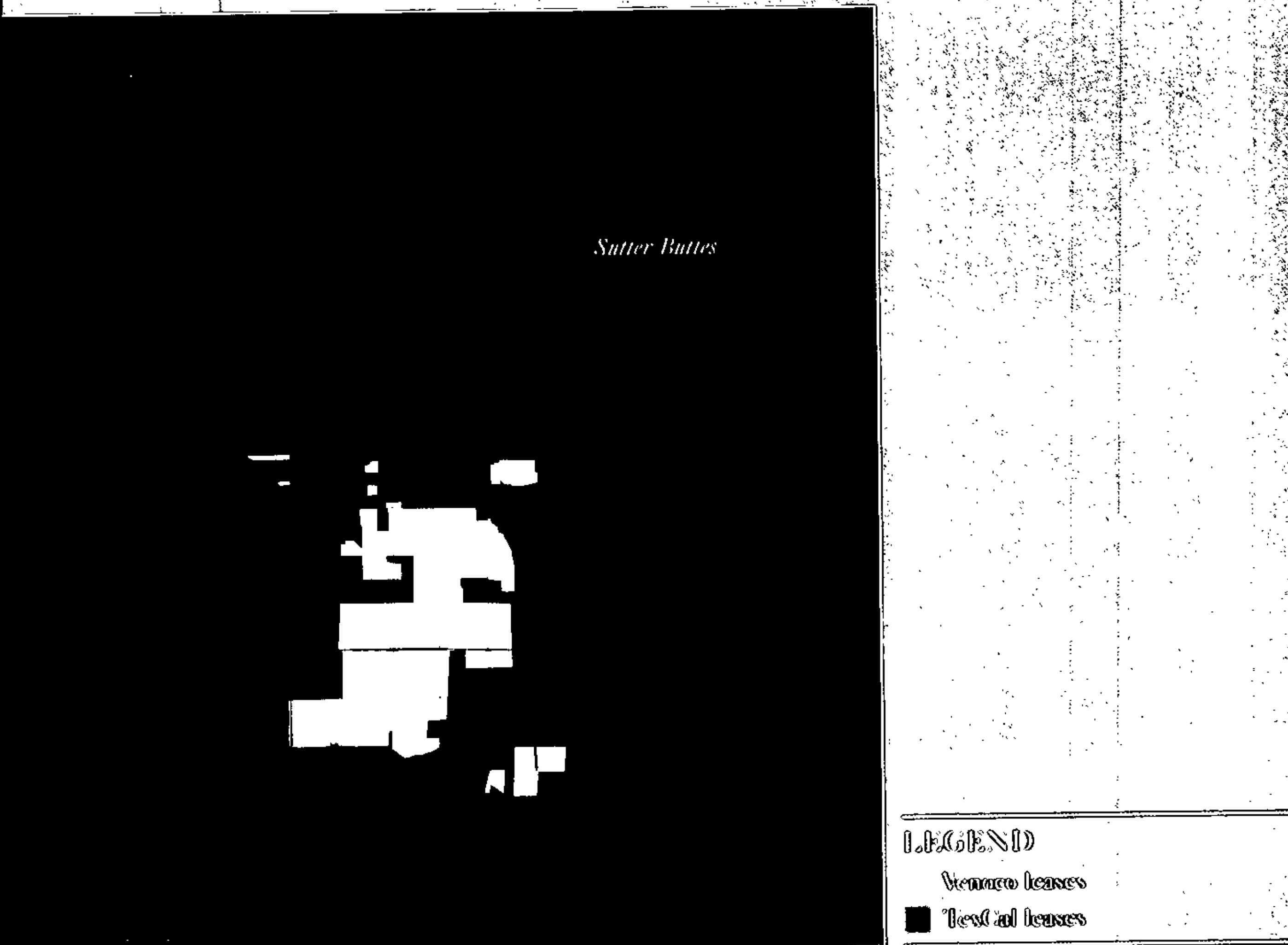
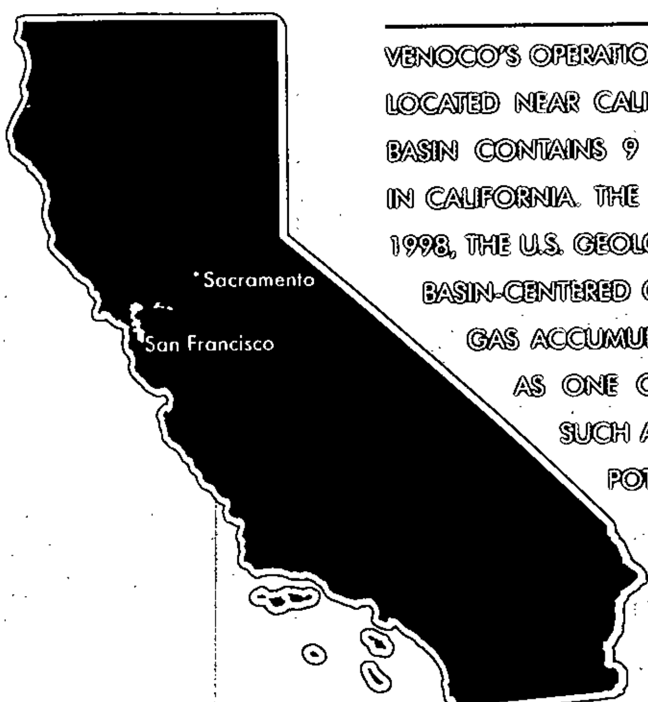

WILLOWS
GRIMES
ARBUCKLE
SACRAMENTO BASIN & DELTA
Sacramento
SUISUN BAY
VAN SICKLE ISLAND
RYER ISLAND
DUTCH SLOUGH
UNION ISLAND
LEGEND
Natural gas fields in the Sacramento Basin
Venoco acreage





VENOCO'S OPERATIONS IN THE SACRAMENTO BASIN (SAC BASIN) ARE EXTENSIVE. LOCATED NEAR CALIFORNIA'S LARGE NORTHERN NATURAL GAS MARKETS, THE BASIN CONTAINS 9 OF THE 10 LARGEST NATURAL GAS PRODUCING FIELDS IN CALIFORNIA. THE BASIN HAS PRODUCED MORE THAN 9.6 TCFE TO DATE. IN 1998, THE U.S. GEOLOGIC SURVEY UNDERTOOK A RIGOROUS EVALUATION OF 33 BASIN-CENTERED GAS SYSTEMS TO DETERMINE THE POTENTIAL FOR NATURAL GAS ACCUMULATIONS. THE REPORT IDENTIFIED THE SACRAMENTO BASIN AS ONE OF SEVEN "SWEET SPOTS" WITH A HIGH POTENTIAL FOR SUCH ACCUMULATIONS WITH AN ESTIMATED 2.5 TCFE OF RESERVE POTENTIAL. WE EXPECT TO INVEST $130 MILLION, OR 56%, OF OUR 2007 CAPITAL PROGRAM TO INCREASE OUR SAC BASIN PRODUCTION, RESERVES AND CASH FLOW PRIMARILY THROUGH LOW-RISK DEVELOPMENT DRILLING.

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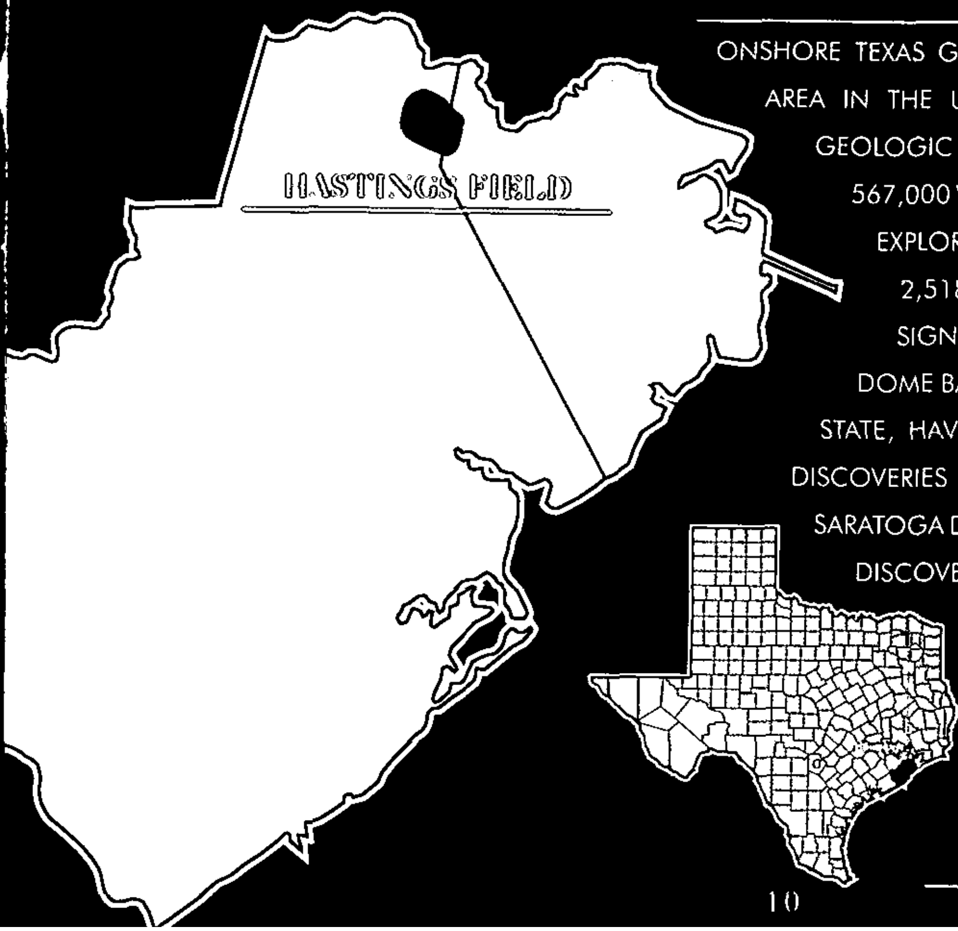

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

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, 2006

☐ **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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

The registrant had no voting or non-voting common stock held by non-affiliates as of the last business day of the registrant's most recently completed second fiscal quarter. There were 42,792,300 shares of common stock outstanding as of March 16, 2007.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its 2007 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. 2006 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" or similar expressions are intended to identify such statements. Forward-looking statements 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;
- operating costs and other expenses;
- wells to be drilled or reworked;
- oil and natural gas prices and demand;
- exploitation, development and exploration prospects;
- asset retirement obligations;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and infill drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- business strategy;
- production of oil and natural gas;
- 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.

Although we believe that the expectations reflected in such forward-looking statements are reasonable, those expectations 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:

- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us;
- competition for available properties and the effect of such competition on the price of those properties;
- oil and natural gas prices;
- risks related to our level of indebtedness;

- our ability to replace oil and natural gas reserves;
- loss of senior management or technical personnel;
- 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;
- costs related to 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;
- general economic, market or business conditions;
- factors affecting the nature and timing of our capital expenditures, including the availability of service contractors and equipment, permitting issues, weather and limits on the number of activities that can be conducted at any one time on our offshore platforms;
- the impact and costs related to compliance with or changes in laws or regulations governing our oil and natural gas operations;
- environmental liabilities;
- risk factors discussed in this report; and
- other factors, many of which are beyond our control.

GLOSSARY OF TECHNICAL TERMS

3D seismic	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 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.

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 below 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 preceding 12 months 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 preceding 12 months 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.
Recompletion	The completion for production of an existing wellbore in a different formulation or producing horizon, either deeper or shallower, from that in which the well was previously completed.
Reserve life	The estimated productive life of a proved reservoir based upon the economic limit of the reservoir producing hydrocarbons in economic quantities, assuming certain price and cost parameters. For purposes of this report, reserve life is determined on a BOE basis by dividing the estimated proved reserves and revisions of previous estimates, excluding property sales, at the end of the year by the oil and natural gas volumes produced during the year.
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 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, including numerous relatively low risk drilling locations.

We have grown to become one of the largest independent oil and natural gas companies in California based on production volumes. According to reserve reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, and DeGolyer & MacNaughton, we had proved reserves of approximately 87.9 MMBOE as of December 31, 2006, of which 56% were oil and 58% were proved developed. The PV-10 value of our proved reserves as of that date was approximately $1.12 billion. 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 Value and Reserve Replacement Costs." Our average net production in the fourth quarter of 2006 was 18,147 BOE/d, implying a proved reserves to production ratio of 13.3 years. The following table summarizes certain information concerning our production in 2006 and our reserves and inventory of drilling locations as of December 31, 2006.

	2006 Net Production			Proved Reserves			
	Oil (MBOE)	Gas (MMCF)	(MBOE)	Total (MMBOE)	% Oil	PV-10 Value ($MM)(1)	Drilling Locations(2)
Coastal California(3)	2,727	1,746	3,018	37.4	87.5	530.5	51
Sacramento Basin	—	11,813	1,969	27.9	—	251.1	547
Texas	684	755	810	22.6	74.5	339.5	56
Total	3,411	14,314	5,797	87.9	56.4	1,121.1	654

(1) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $5.64 per MMBtu for natural gas, in each case adjusted for regional price differentials and similar factors.

(2) Represents total gross drilling locations identified by management as of December 31, 2006. Of the total, 355 locations are classified as proved.

(3) Includes properties offshore and onshore southern California.

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. Fields of this type often have a significant number of potential drilling prospects. One of our primary objectives is to continue to increase the amount of oil and natural gas ultimately recovered from these fields, thereby increasing our reserves and production. Our offshore California fields and our Texas Gulf Coast fields generally have well-established production histories and exhibit relatively moderate production declines. As of December 31, 2006, our proved reserves to production ratio was 13.3 years and our proved developed reserves to production ratio was 7.7 years, in each case based on production during the fourth quarter of 2006. We believe that this relatively stable base of long-lived production is a strong platform to support further growth in our reserves and production.

Attractive reserve replacement costs. From our inception in 1992 through December 31, 2006, we made approximately $1,051.8 million in capital expenditures to acquire, develop and/or discover 142.4 MMBOE of proved reserves, an average reserve replacement cost (including reserve revisions) of $7.39 per BOE. These capital expenditures consisted of $592.4 million used to complete 39 acquisitions and $459.4 million used for development and exploration projects. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—PV-10 Value and Reserve Replacement Costs" for a description of how we calculate reserve replacement cost.

Significant drilling inventory and growth potential. As of December 31, 2006, we had identified 654 drilling locations on our properties, and we anticipate identifying additional locations on those properties as we pursue our exploitation and development activities. As of December 31, 2006, we controlled a total of 324,896 gross acres (237,227 net). We believe that the continued exploitation and development of our properties will allow us to increase our proved reserves and our average net daily production even if we do not make additional acquisitions. In addition, we believe that improved technology, our experienced technical staff and our substantial acreage position will allow us to further expand our proved reserves and production through exploration activities.

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 have a twelve-person team of engineers and geologists dedicated exclusively to our operations in the basin, and have six drilling and two completion/workover rigs under contract there as of March 15, 2007. 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 discount 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 20 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 44 engineers and geoscientists as of March 15, 2007. 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 94% of our production in the fourth quarter of 2006. 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.

Good 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:

Grow through relatively low-risk exploration, exploitation and development projects. We operate properties with substantial volumes of remaining hydrocarbons. We believe that we can expand reserves and increase production from these properties on a cost-effective basis with relatively limited risk. Our exploration, exploitation and development capital expenditures have increased significantly in recent years, from $23.2 million in 2004 to $83.6 million in 2005 and to $189.2 in 2006. We expect that our exploration, exploitation and development capital expenditures in 2007 will be approximately $230.0 million.

Make opportunistic acquisitions of underdeveloped properties. We pursue acquisitions that expand our 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. Our March 2006 acquisition of TexCal Energy (LP) LLC, with its significant property positions in the Sacramento Basin and the Hastings complex in Texas, demonstrates our successful implementation of this strategy. Historically, we have had success acquiring offshore California properties from major oil companies, including Chevron and ExxonMobil. We believe that we have established a strong reputation as a reliable and safe operator and that this will lead to future opportunities to acquire properties from major oil companies. In addition, many large properties in California are held by smaller independent companies that lack the resources to exploit them fully. We intend to pursue these opportunities to selectively expand our portfolio of properties.

Actively grow in the Sacramento Basin. We intend to continue to pursue an active drilling and acreage acquisition program in the Sacramento Basin. In the fourth quarter of 2006, our average net production in the basin was 39,994 Mcf/d, or 303% of our production in the area in the fourth quarter of 2004. We expect to continue our growth in this area, which we believe has 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, 2006, we controlled approximately 39,000 net acres with proven, probable and possible Monterey reserves and are actively seeking additional acreage.

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 operating costs. We expect that growth in the Sacramento Basin will allow us to improve our operating margins, as production expenses associated with our Sacramento Basin wells tend to be low relative to most of our other wells. We also intend to improve our operating margins through a reduction in remedial activities conducted in the Hastings complex and other cost control measures.

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 2006 through 2010. Using a blend of purchased floors and collars, we maintain a balanced oil and natural gas derivative position intended to limit downside price risk while maintaining the potential to benefit from price increases on a substantial portion of our anticipated production. We will continue to pursue our hedging strategy in order to protect our ability to execute our capital expenditure plan and to preserve upside potential. See "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our derivative/hedging activity.

Recent Developments

Asset Acquisitions. In March 2007 we entered into an agreement to purchase the West Montalvo field near Ventura, California for approximately $63.0 million. Also in March 2007, we entered into a separate agreement to purchase the Manvel field in Brazoria County, Texas and certain other assets. The purchase price in this transaction will be approximately $48.0 million. We expect to complete both acquisitions in the second quarter of 2007. The purchase price in each transaction is subject to certain adjustments, and completion of each is subject to customary closing conditions.

Initial Public Offering. We completed an initial public offering of our common stock on November 17, 2006. Our net proceeds from the offering were approximately $157.5 million, which we used to reduce our indebtedness. Our common stock began trading on the New York Stock Exchange under the symbol "VQ" in connection with the offering.

CO_2 Project with Denbury. In November 2006, we entered into an option agreement with Denbury Resources relating to a potential CO_2 enhanced recovery project in the Hastings complex. Pursuant to the agreement, Denbury will pay us a total of $50.0 million for an option to acquire our interest in parts of the complex and certain related property for use in an enhanced recovery project in which we will have a continuing interest. Of the total option payment, $37.5 million was paid in December 2006, $7.5 million will be paid in November 2007 and the remaining $5.0 million will be paid in November 2008. No part of the option payment is refundable. Denbury may not exercise the option until September 2008. The initial exercise period will end in October 2009, subject to Denbury's right to extend it for successive one-year periods until 2016 for an annual extension fee of $30.0 million.

Following the exercise of the option, Denbury will either purchase the properties subject to the option or enter into a volumetric production payment arrangement with us with respect to the properties. The purchase price or volumetric production payment will be based on the value of the properties as determined with respect to the net proved reserves associated with the properties based on then-existing operations and NYMEX forward strip pricing, subject to certain adjustments. The

$50.0 million option payment will not be deducted from the purchase price or payment. Contemporaneously with its exercise of the option, Denbury will commit to a development plan for the properties that will call for it to make capital expenditures of at least $178.7 million over five years. As part of the plan, Denbury will be responsible for providing the necessary CO_2. Following the exercise of the option, we will retain 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. We will continue our operations on the properties until the option is exercised. The success of any CO_2 enhanced recovery project is 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.

TexCal Transaction. We acquired TexCal on March 31, 2006 for $456.8 million in cash. According to a reserve report prepared by DeGolyer & MacNaughton, as of December 31, 2005, TexCal had proved reserves of 31.4 MMBOE, 31.2% of which were located in the Sacramento Basin. TexCal's average net production for 2005 was 4,340 BOE/d and its average net production in the first quarter of 2006 was 5,467 BOE/d. The TexCal transaction is consistent with our strategy of acquiring large, mature fields with established reserves in our core areas of operation. We financed the acquisition through aggregate borrowings of $469.5 million under an amendment and restatement of our existing revolving credit facility and a new senior secured second lien term loan facility, which we refer to collectively as the credit facilities. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements."

Description of Properties

The following table summarizes our proved reserves by area and related information as of December 31, 2006, as derived from reserve reports prepared by NSAI and DeGolyer & MacNaughton.

	Proved Reserves (MMBOE)	% of Total Reserves	% Oil	PV-10 Value ($MM)	% of Total PV-10
Coastal California					
South Ellwood	20.0	22.8	83.1	281.3	25.1
Santa Clara Federal Unit	12.6	14.3	94.7	194.6	17.4
Dos Cuadras	3.0	3.4	83.6	26.4	2.4
Onshore	1.8	2.1	93.3	28.3	2.5
Sacramento Basin					
Greater Grimes	23.0	26.1	—	198.9	17.7
Willows	2.4	2.8	—	29.0	2.6
Other	2.4	2.8	—	23.2	2.1
Texas					
Hastings Complex	13.8	15.6	100.0	184.1	16.4
Constitution	2.1	2.4	45.3	64.0	5.7
Other	6.8	7.7	31.8	91.3	8.1
Total	87.9(1)	100.0	56.4	1,121.1	100%

(1) The total proved reserve estimate is comprised of 45.6 MMBOE included in the NSAI report and 42.3 MMBOE included in the DeGolyer & MacNaughton report.

Coastal 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. We acquired our interest 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 associated 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, 2006, we had 23 producing wells and three injection wells in the field. During December 2006, average net production at the field was 3,301 Bbl/d of oil and 2,370 Mcf/d of natural gas. In 2006, our activities in the field were focused on working over existing wells and upgrading facilities to improve reliability and reduce downtime. We also completed an exploration well to the north flank of the Monterey formation in 2006. This well was dry and will be converted into a water injection well in the future. We recently completed a low-energy, high resolution seismic shoot which we are using to assess potential additional drilling opportunities north of the field. We are also pursuing the permits necessary to extend the area covered by our lease.

We own processing and transportation facilities at South Ellwood, including 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 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. Oil produced at the South Ellwood field has been transported by barge since operations at the field commenced in 1966. 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. The barge has historically delivered the oil primarily to Long Beach, California for purchase by Shell. However, Shell informed us in August 2006 that it was not willing to accept further deliveries from this barge at its Long Beach terminal. In response to Shell's decision, we have sold recent shipments of oil production from the field to a refinery in the San Francisco area on a shipment-by-shipment basis. The prices we have received from the sales to that refinery are discounted relative to the prices we received from Shell. In 2007, this discount has been as high as $16.45 per Bbl, although more recently it has declined to as low as $6.83 per Bbl. Also, the transportation costs associated with these sales have been higher, although the increase has not been material. We have recently entered into agreements pursuant to which we expect to be able to deliver shipments of production from the field to Long Beach, California and then transport the production via pipeline for sale to any of several refineries in the Long Beach area. Subject to our ability to enter into an acceptable sales agreement with any of the available refineries, receipt of necessary permits and the resolution of any logistical or operating issues that may arise, we expect to begin making deliveries pursuant to this arrangement in the second quarter of 2007. Initial sales will likely be made on a spot basis. We expect that the new arrangement will provide a more competitive environment for sales of our production and will ultimately enable us to obtain prices comparable to those we received from Shell. On a longer term basis, we are also pursuing the possibility of using an onshore pipeline instead of a barge, but construction of the pipeline would require governmental approvals and would not be completed before late 2008 at the earliest. The pipeline project is currently in the permitting stage. See "Risk Factors—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." Natural gas produced at the field is transported by common carrier pipeline.

In addition to our processing and transportation facilities, we operate, and have a 78% interest in, two seep tents located in the vicinity of the drilling platform. These tents capture naturally seeping natural gas from the ocean floor at a net rate of approximately 200 Mcf/d. The captured natural gas is transported to the onshore facility by a separate pipeline. The seep tents have helped to reduce air emissions and contain the flow of naturally occurring natural gas seeps onto the Santa Barbara coastline.

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 field and the associated facilities from Chevron in February 1999. Production is transported via pipeline to Los Angeles, California. We operate the field 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, 2006, we had 19 producing wells and two active injection wells in the field. The primary producing horizons initially were the Monterey and Upper Sespe. More recently, recompletions in the Upper Topanga horizon have accounted for a larger share of production. 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. During December 2006, average net production at the field was 3,497 Bbl/d of oil and 1,807 Mcf/d of natural gas. In 2006, our primary focus in the field was on drilling infill development wells. We drilled three development wells during the year, all of which were successful. We also drilled two exploration wells, one of which was dry and the other of which is productive. We are assessing the possibility of further waterflood expansion in the Upper Topanga formation, which has demonstrated a response to waterflooding.

Chevron shut in production at platform Grace in 1997, and we currently use it 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. We are finalizing a development plan relating to the possible return of platform Grace to production through the redrilling of selected wells and upgrades to facilities. We do not currently expect to generate significant production from the platform before the second half of 2007 at the earliest. In March 2003, we granted an option to Crystal Energy LLC to lease or purchase platform Grace for use as a liquid natural gas, or LNG, terminal. In March 2006, Crystal Energy assigned its interest in the option agreement to Clearwater Port LLC, that agreement was terminated and we entered into a new agreement with Clearwater. Under the new agreement, Clearwater has an option to purchase or lease platform Grace for use as an LNG terminal. The option will become exercisable on January 1, 2008 and will expire on March 1, 2012. If Clearwater exercises the option, we will cease any exploration, exploitation and development activities then conducted from the platform and Clearwater will commence construction of its LNG facility. Clearwater's right to exercise the option is subject to, among other things, its receipt of certain regulatory approvals relating to the construction and operation of its LNG facility and the satisfaction of certain financial requirements. If the option is exercised, Clearwater will pay us an annual fee during the period in which the LNG facility is being constructed. This annual fee will initially be $6.0 million, and will increase over time to a potential maximum of $10.0 million. Following the commencement of operations at the facility, Clearwater will pay us an annual fee based on the amount of LNG processed, produced or stored at the facility. The fee will be equal to approximately $12.0 million for the first 800,000 MMBtu/d and $0.04 per MMBtu for volumes in excess of 800,000 MMBtu/d on an average annual basis.

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 DCOR, LLC. Production is transported via pipeline to Los Angeles, California. As of December 31, 2006, there were 93 producing wells and 16 injection wells in the field. During December 2006, average net production at the field was 628 Bbl/d of oil and 116 Mcf/d of natural gas.

Onshore Coastal California. Our onshore properties in the coastal California region include the Beverly Hills West field and the Santa Clara Avenue 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 from Wainoco Oil & Gas Company 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 from three other operators. We operate the field and have working interests ranging from 43% to 100%. During December 2006, aggregate average net production from our onshore coastal California properties was 586 Bbl/d of oil and 20 Mcf/d of natural gas.

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, containing nine of the state's ten largest natural gas fields by that measure. It is located near northern California natural gas markets and has substantial natural gas gathering infrastructure and pipeline capacity. It is approximately 210 miles long and 60 miles wide and contains a variety of different geologic plays. We are one of the largest producers in the area, with average net production of 39,994 Mcf/d in the fourth quarter of 2006. We own 3D seismic data covering 500 square miles in the basin and are in the process of analyzing the 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 111,160 net acres as of December 31, 2006. We operate substantially all of the fields and have an average working interest of 71%.

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. We had 298 producing wells in the fields as of December 31, 2006. Average net production from the fields was 37,114 Mcf/d in December 2006.

We have been engaged in an aggressive drilling program in these fields, drilling 60 wells and completing 34 workovers in 2006. This program has resulted in significant increases in production and reserves. For example, we increased average net production from the Sacramento Basin properties we acquired in the TexCal transaction from 15,493 Mcf/d in March 2006 to 17,762 Mcf/d in December 2006, and the proved reserves associated with those properties rose from 58,632 MMcf as of December 31, 2005 to 118,029 MMcf as of December 31, 2006. We have identified 334 drilling locations in the fields as of December 31, 2006, of which 228 are classified as proved.

Other Sacramento Basin. We have a number of other fields in the Sacramento Basin, located in Solano, Contra Costa, San Joaquin and Colusa Counties. We operate each of these fields and have working interests ranging from 42% to 100%. As of December 31, 2006, we had a total of 52 active 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. Total average net production from these other Sacramento Basin fields was approximately 4,683 Mcf/d in December 2006.

Texas

Hastings Complex. Our largest property in Texas is the Hastings complex, which encompasses approximately 6,624 net acres located approximately 30 miles south of Houston in Brazoria County. The Hastings complex is comprised of the West Hastings Unit, the East Hastings field and the Hastings field. We have an 89% working interest in the West Hastings Unit and 100% working interests in the East Hastings field and the Hastings field. We operate the entire complex.

The Hastings 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, 2006, we had 106 producing wells in the complex. In 2006, we engaged in a recompletion and workover program in the complex involving over 140 wells. Work performed included returning idle wells to production, upgrading artificial lift systems and completing workovers. This program contributed to a 38% increase in average net production from the complex from March 2006 to December 2006, and we are continuing to pursue it in 2007. We are also evaluating potential infill development well drilling opportunities in the complex. Average net production from the complex was 2,434 Bbl/d of oil in December 2006. We have been engaged in a variety of remedial facility improvements and clean-up activities at the complex since April 2006 but expect to substantially reduce these activities after June 2007.

In November 2006, we entered into an option agreement with a subsidiary of Denbury Resources relating to a potential CO_2 enhanced recovery project in the Hastings complex. Pursuant to the agreement, Denbury will pay us a non-refundable fee of $50.0 million for an option to acquire our interest in the West Hastings Unit, the East Hastings field and certain related property for use in an enhanced recovery project in which we will have a continuing interest. Following the exercise of the option, Denbury will either purchase the properties subject to the option or enter into a volumetric production payment arrangement with us with respect to the properties. As part of the plan, Denbury will be responsible for providing the necessary CO_2. Contemporaneously with its exercise of the option, Denbury will commit to a development plan for the properties that will call for it to make capital expenditures of at least $178.7 million over five years. 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 the third anniversary of the date the option exercise is given effect. During the term of the option, we will not enter into or amend any agreement in a manner that would have a material adverse effect on Denbury's rights under the option agreement. Each of us and Denbury will have a right of first refusal with respect to any proposed sale or transfer by the other of its interests under the option agreement. The option agreement also establishes an area of mutual interest with respect to us and Denbury in specified areas adjacent to the properties. For additional information regarding the option agreement, see "—Recent Developments—CO_2 Project with Denbury."

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, 2006, there were two producing wells in the field. During December 2006, average net production from the field was approximately 34 Mcf/d of natural gas and

39 Bbl/d of oil. In 2007, we plan to recomplete one well and we may drill an additional development well. We are also evaluating 3D seismic data covering 13 square miles of the field to assess additional development opportunities.

Other. Our other Texas properties encompass a total of 10,405 net acres in the southern Gulf Coast region. Our average working interest in these fields is 92% and we operate substantially all of our production there. As of December 31, 2006, there were a total of 69 producing wells in these fields. Total average net production from the fields in December 2006 was 358 Bbl/d of oil and 3,126 Mcf/d of natural gas. In 2006, we drilled two wells in our Word field and spudded a well in our Giddings field that we expect to complete in the first half of 2007. If the Giddings field well is successful, we expect to drill another well there in 2007. We also plan to refracture three existing wells and drill two new development wells in our AWP field, and to shoot 13.5 square miles of 3D seismic data in our Liberty South field.

Oil and Natural Gas Reserves

The following table sets forth our net proved reserves for the dates indicated. Our reserve estimates as of December 31, 2004 and 2005 are based on reserve reports prepared by NSAI and our reserve estimates as of December 31, 2006 are based on reserve reports prepared by NSAI and 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 those engineers' review of production histories and other geological, economic, ownership and engineering data.

	December 31,		
	2004(1)	2005	2006
Net proved reserves (end of period)			
Oil (MBbl)			
Developed	28,035	24,154	37,497
Undeveloped	11,900	11,146	12,110
Total	39,935	35,300	49,607
Natural gas (MMcf)			
Developed	49,418	53,390	79,796
Undeveloped	20,458	20,663	150,156
Total	69,876	74,053	229,952
Total proved reserves (MBOE)	51,581	47,642	87,932

(1) Does not include reserves of Marquez Energy. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Other Accounting Matters—Acquisition of Marquez Energy."

As of December 31, 2006, our proved reserves totaled 87.9 MMBOE (58% proved developed), comprised of 49,607 MMBbl of oil (56% of the total) and 229,952 MMcf of natural gas, and had an estimated proved reserves to production ratio of 13.3 years. See "Glossary of Technical Terms" for an explanation of the terms "proved reserves," "proved developed reserves," "proved undeveloped reserves" and related terms. You should not place undue reliance on estimates of proved reserves. See "Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantity and present value of our reserves."

Production, Prices and Costs

The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and natural gas for the periods indicated. 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.

	Historical		
	Year Ended December 31,		
	2004(1)	2005(1)	2006(2)
Production Volume			
Natural gas (MMcf)	5,826	7,588	14,314
Oil (MBbls)	3,101	2,953	3,411
MBOE	4,072	4,218	5,797
Daily Average Production Volume			
Natural gas (Mcf/d)	15,918	20,789	44,346
Oil (Bbl/d)	8,472	8,090	9,958
BOE/d	11,125	11,555	17,349
Oil Price per Bbl Produced (in dollars)			
Realized price	$ 34.69	$ 45.66	$ 55.92
Realized commodity derivative loss and amortization of derivative premiums	(5.47)	(7.46)	(8.38)
Net realized	$ 29.22	$ 38.20	$ 47.54
Natural Gas Price per Mcf Produced (in dollars)			
Realized price	$ 5.77	$ 7.45	$ 6.04
Realized commodity derivative gain (loss) and amortization of derivative premiums	(0.11)	(0.11)	0.36
Net realized	$ 5.66	$ 7.34	$ 6.40
Average Sale Price per BOE(3)	$ 30.42	$ 39.55	$ 44.13
Expense per BOE			
Production expenses(4)	$ 12.17	$ 12.81	$ 15.09
Transportation expenses	0.72	0.62	0.61
Depreciation, depletion and amortization	4.05	5.14	10.91
General and administrative expense(5)	2.77	3.79	4.88
Interest expense, net(5)	0.56	3.24	8.52

(1) Amounts shown include Marquez Energy from July 1, 2004. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Other Accounting Matters—Acquisition of Marquez Energy."

(2) 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.

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

(4) Production expenses are comprised of oil and natural gas production expenses and production taxes.

(5) Net of amounts capitalized.

Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2004 through December 31, 2006 (including Marquez Energy from the time we acquired it in March 2005). 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 wells.

	Development Wells Drilled		
	2004	2005	2006
Producing			
Gross	4.0	16.0	17.0
Net	3.8	7.9	12.4
Dry			
Gross	—	1.0	1.0
Net	—	0.2	0.7

	Exploration Wells Drilled		
	2004	2005	2006
Producing			
Gross	2.0	3.0	42.0
Net	1.4	1.9	31.5
Dry			
Gross	1.0	5.0	10.0
Net	0.5	3.2	8.2

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 exploration wells drilled in 2006, 47 were drilled in the Sacramento Basin. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Capital Expenditures."

Oil and Natural Gas Wells

The following table details our working interests in producing wells as of December 31, 2006. 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	337	189.2	56.0%
Natural gas	358	186.9	52.2%
Total	695	376.1	54.0%

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2006. 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**
Coastal California						
South Ellwood	1,543	1,543	6,174	6,174	7,717	7,717
Santa Clara Federal Unit	36,000	27,360	—	—	36,000	27,360
Dos Cuadras	5,875	1,460	—	—	5,875	1,460
Paredon(2)	—	—	4,112	4,095	4,112	4,095
Onshore	1,016	475	31,798	11,708	32,814	12,183
Total Coastal California	44,434	30,838	42,084	21,977	86,518	52,815
Sacramento Basin	131,651	111,000	81,252	58,615	212,903	169,615
Texas	22,909	13,919	2,566	877	25,475	14,796
Total	198,994	155,757	125,902	81,469	324,896	237,226

(1) Approximately ninety percent of our historical undeveloped leasehold acreage is, by the terms of the applicable lease(s), held by production from the other producing wells and is not subject to expiry unless production ceases. The Paredon leases, totaling a net 4,096 acres, are subject to expiry in 2013 and 2014.

(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 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, 2006, approximately 76% of our revenues were generated from sales to four purchasers, ConocoPhillips (31%), Enserco Energy (20%), Shell Trading (US) Co. (13%) and Gulfmark Energy (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. Beginning in August 2006, we have sold oil production from the South Ellwood field on a shipment-by-shipment basis. See "—Description of Properties—Coastal California—South Ellwood Field."

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 33,000 net square feet of office space in Denver, Colorado, where our principal office is located. The lease for the Denver office expires in 2013. 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 remains 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, 2006, we had approximately 250 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. We believe that our business operations are in substantial compliance with current laws and regulations. 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. A public draft of the environmental impact report relating to the request has been issued and the issuance of a final report is pending.

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 U.S. 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 ("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. 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 6 to our financial statements, we have estimated the present value of our aggregate asset retirement obligations to be $42.0 million as of December 31, 2006. 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 6% and 8%. Actual costs may exceed our estimates. Our financial statements do not reflect any reserves 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 $2.0 and $5.0 million. These costs are 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 has a remaining useful life of 20 years. 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, and we work diligently to ensure continuing compliance. However, from time to time we receive notices of noncompliance with Clean Air Act and other requirements from relevant regulatory agencies. We received one notice of violation ("NOV") from the Santa Barbara County Air Pollution Control District in 2006. This NOV is currently pending. We also received one NOV from the Ventura County Air Pollution Control District in 2006, which has been resolved. We do not expect to incur significant penalties with respect to any outstanding NOV.

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, 2006.

Name	Age	Position
Timothy Marquez	48	Chairman and Chief Executive Officer
William Schneider	45	President
David B. Christofferson	58	Chief Financial Officer
Mark DePuy	51	Senior Vice President, Chief Operating Officer
Terry L. Anderson	59	General Counsel and Secretary
Douglas J. Griggs	47	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.

David B. Christofferson became our CFO in November 2004. Mr. Christofferson was CFO of Marquez Energy from November 2002 until joining our company in his current capacity. Prior to joining Marquez Energy, Mr. Christofferson served as General Counsel and CFO of Esenjay Exploration, Inc. (f/k/a Frontier Natural Gas Corporation), a NASDAQ-listed company, from 1988 until May 2002. Between May and November 2002, he was a private consultant. Mr. Christofferson holds

B.A. and J.D. degrees from the University of Oklahoma and a Master of Divinity degree from Phillips University (now a part of the University of Tulsa). Mr. Christofferson will resign as our CFO on April 3, 2007.

Mark DePuy became our Vice President, Northern Assets, in August 2005 and was promoted to Senior Vice President and Chief Operating Officer in January 2006. Prior to joining us, he spent 27 years with Unocal in a variety of domestic and international operating and business planning roles, most recently as a corporate planning manager for worldwide operations. With Unocal, Mr. DePuy spent 13 years working on operations onshore and offshore coastal California. He has an M.B.A. from U.C.L.A. and a B.S. in petroleum engineering from the Colorado School of Mines.

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-five 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, project management 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.

Timothy Ficker. Prior to joining us, Mr. Ficker, 39, 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. He will become our CFO effective upon Mr. Christofferson's resignation as described above. 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.

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 Securities and Exchange Commission (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, 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. A decrease in oil and natural gas prices could have a material adverse effect on our business, financial condition or results of operations.

A substantial decline in the prices we receive for our oil and natural gas production would have a material adverse effect on us, as our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon those prices. For example, changes in the prices we receive for our oil and natural gas affect our ability to finance capital expenditures, make acquisitions, borrow money and satisfy our financial obligations. In addition, declines in prices could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our reserves. 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, especially given current world geopolitical conditions. Furthermore, the oil we produce in California is generally heavier than, and therefore sells at a discount to, premium grade light oil, and the amount of that discount varies over time. The price for the heavier oil we produce is affected by factors that may not have the same impact on the price of premium grade light oil. For example, in 2005, the price of our oil was negatively affected by an increase in the supply of heavy oil from Ecuador, which increased the discount we received for our oil compared to premium grade light oil. We cannot predict how the discount will change in the future, and it is possible that it will increase. The difficulty involved in predicting the discount also makes it more difficult for us to effectively hedge our production. Transportation costs and capacity constraints can also reduce the prices we receive for our oil and natural gas production. The prices of oil and natural gas are affected by a variety of other factors that are beyond our control, including:

- changes in global supply and demand for oil and natural gas;
- commodity processing, gathering and transportation availability;
- actions of the Organization of Petroleum Exporting Countries;
- domestic and foreign governmental regulations and taxes;
- domestic and foreign political developments, including embargoes, affecting oil-producing activity;
- 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.

These factors and the volatility of the energy markets generally make it extremely difficult to predict future oil and natural gas price movements.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or 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 our future estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of our future net cash flows. Our estimated proved reserves at December 31, 2005 were approximately 3.9 MMBOE lower than at December 31, 2004, primarily because of the sale of our Big Mineral Creek property (partially offset by net reserve acquisitions during the year), depletion that occurred as we produced oil and natural gas from our properties and other adjustments based on reservoir information. Similar events in the future could lead to downward revisions of our reserve estimates, and those revisions could be material.

At December 31, 2006, 42% of our estimated proved reserves were proved undeveloped and 5% 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 of the production and the expenses related to the development of oil and natural gas properties will affect both the timing 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 value 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. Any significant variations from the interpretations or assumptions used in our estimates, such as increased or decreased production levels or changes of conditions and information resulting from new or reinterpreted seismic data or otherwise, could cause the estimated quantities and PV-10 value of our reserves to change materially.

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.

For example, in May 2005, we encountered downhole mechanical problems during a routine workover on a well in the South Ellwood field. As a result of the problems, average net production from the well dropped from 1,155 BOE/d in April 2005 to 262 BOE/d in May 2005 before being restored to 1,309 BOE/d in December 2005. In addition, our efforts to restore production at the well required us to delay the implementation of some other projects. We may experience similar problems and delays from time to time in the future. 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. For example, our production in the first quarter of 2006 was adversely affected by heavy rain and flooding in northern California.

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 insurance 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. 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.

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 production from the field in December 2006 was 3,301 Bbl/d, or approximately 17% of our aggregate net production for the month. 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.

From time to time, the barge is unavailable due to maintenance and repair requirements. For example, it was out of service for part of August 2006 due to scheduled maintenance. In addition, in October, 2006, it was involved in a minor collision with a tugboat and was out of service for repair and inspection for approximately two weeks. In March 2007, it was out of service for inspection for approximately one week. 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.

As described in "Business and Properties—Description of Properties—Coastal California—South Ellwood Field," the owner of the refinery to which we have historically delivered oil production from the field informed us in August 2006 that it was unwilling to accept further deliveries from the barge. As a result, we have sold recent shipments of oil production from the field to a refinery in the San Francisco area on a shipment-by-shipment basis. However, the prices we have received from the sales to that refinery are lower than we received from previous sales, and the associated transportation costs are higher. Any new delivery or sales arrangements, including the arrangement described in "Business and Properties—Description of Properties—Coastal California—South Ellwood Field," may require time to implement and may require us to accept lower prices for our production and/or incur higher transportation costs. Our ability to implement a new delivery or sales arrangement may be adversely affected by the fact that there are only a limited number of refineries in California. Further, our existing storage facilities have only limited capacity. 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 debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

As of December 31, 2006, we had total indebtedness under the credit facilities and our 8.75% senior notes due 2011 of approximately $529.0 million, which bore interest at a weighted average rate of 9.49%. Because we must dedicate a substantial portion of our cash flow from operations to the payment of interest on our debt, that portion of our cash flow is not available for other purposes. In addition, borrowings under our credit facilities bear interest at rates that vary with changes in market rates. Accordingly, an increase in market rates could significantly increase our debt service obligations. Our ability to make scheduled principal and 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. Our cash flow from operations and other capital resources may not be sufficient to pay the principal and interest on our debt in the future. If our cash flow and other capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay scheduled capital projects, sell material assets or operations or restructure our debt. In the event that we are required to dispose of material assets or operations, obtain additional capital or restructure our debt to meet our debt service and other obligations, the terms of any such transaction may not be favorable to us and may not be completed in a timely fashion. In addition, our credit facilities contain mandatory prepayment provisions that would limit our ability to respond to a shortfall in our expected liquidity by selling assets, issuing equity securities or incurring additional indebtedness. In particular, the facilities would require us to use some or all of the proceeds of such transactions to reduce amounts outstanding under one or both of those 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."

Our level of indebtedness, and the covenants contained in the indenture governing our senior notes and the agreements governing our credit facilities, which we refer to collectively as 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 from sales of assets and stock 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 or our business, the industry in which we operate and/or commodity prices;
- impairing our ability to withstand successfully a downturn in commodity prices or 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.

The covenants contained in our debt agreements became more demanding in some respects on March 31, 2007 and will tighten further on September 30, 2007, as described in "Management's Discussion and Analysis of Financial Condition and Results of Operation—Liquidity and Capital Resources—Capital Resources and Requirements." Our ability to comply with these covenants in future periods will depend on our ongoing financial and operating performance, which in turn will be subject to general economic conditions and financial, market and competitive factors, in particular the selling prices for our oil and natural gas and our ability to successfully implement our overall business strategy.

The breach of any of the covenants in 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. In the event of an actual or potential default, we could attempt to refinance the debt 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. The terms of our debt agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and the value of our assets and our operating performance at the time of such offering or other financing. We may not be able to complete any such offering, refinancing or sale of assets on desirable terms or at all.

We may incur substantially more debt. This could further exacerbate the risks associated with our substantial indebtedness.

We may be able to incur substantial additional indebtedness in the future under the covenants set forth in our debt agreements. If new debt is added to our current debt levels, the related risks that we now face could intensify. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations. The acquisitions we expect to complete in the second quarter of 2007 will increase our indebtedness. See "Business and Properties—Recent Developments—Asset Acquisitions."

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 from 5% to 3%. Additionally, the method of measuring carbon dioxide levels was made more stringent. To comply with these new requirements, we shut in some high gas-to-oil ratio wells, which reduced our gas sales from the field from 4.2 MMcf/d in 2002 to 2.5 MMcf/d in 2003. Similar events may occur in the future. These events, many of which are beyond our control, could have a material adverse effect on our operations and financial condition and could reduce estimates of our proved reserves.

Our hedging arrangements involve credit risk and may limit future revenues from price increases and 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;
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received; or
- there is a sudden, unexpected event that materially impacts oil or natural gas prices.

Our total net realized losses on derivative instruments were $17.6 million, $20.7 million and $15.3 million for the years ended December 31, 2004, 2005 and 2006, respectively. In addition, we have incurred substantial unrealized commodity derivative losses in some recent periods, including total net losses of $32.2 million in 2005. These unrealized losses resulted primarily from the fact that hedge accounting treatment is not applied to all of our derivative positions. Changes in the fair market value of the derivatives were therefore required to be recognized in the statement of operations. We may incur realized and unrealized losses of this type in the future. Hedging arrangements may also limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. 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.

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. Further, the obligation to post cash or other collateral could, if imposed, adversely affect our liquidity.

We may not be able to raise the capital necessary to replace our reserves.

Reserves can be replaced through acquisitions of new properties or the exploration, exploitation and development of existing properties. Either approach requires substantial capital, and capital may not always be available to us on reasonable terms or at all. If our cash flow from operations and cash available from other sources is less than we anticipate, we may not be able to finance the capital expenditures, or complete the acquisitions, necessary to replace our reserves. A reduction in our reserves could, in turn, further limit the availability of capital, 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 in part on the estimated quantities of our proved reserves.

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. We endeavor to utilize the knowledge of the fractured Monterey shale formation we have developed in our offshore drilling operations in onshore exploratory drilling, and our assumptions about the consistency of this formation may not be correct. 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 beyond our control, 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.

A failure to complete successful acquisitions would limit our growth.

Our strategy is to increase our reserves and production, in part through the acquisition of 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. 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. The risks normally associated with acquisitions are heightened in the current environment, as market prices of oil and natural gas properties are generally high compared to historical norms. In addition, we may face greater risks to the extent we acquire properties in areas outside of California, as we did when we acquired TexCal, 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.

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.

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 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. In addition, our operations could be adversely affected by federal and state laws that require environmental impact studies to be conducted before governmental authorities can take certain actions, including in some cases the issuance of permits to us. Environmental risks are generally not fully insurable.

We could also be adversely affected by existing or future tax laws and regulations. For example, proposals have been made to amend federal and California law to impose "windfall profits" taxes or other types of additional taxes on oil companies. If any of these proposals become law, our costs would increase, possibly materially.

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, reduce our cash flow 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 along 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. 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.

The geographic concentration of our operations and oil and natural gas reserves in California makes us vulnerable to localized operating and other risks.

Most of our oil and natural gas reserves are located in California. Because our reserves are not as diversified geographically as those of many of our competitors, our business is subject to local conditions to a greater extent than other, more diversified companies. Any regional events, including price fluctuations, natural disasters and restrictive regulations, that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than they would if our reserves were more geographically diversified.

Because we cannot control activities on properties we do not operate, we cannot control the timing of those projects. Our inability to fund required capital expenditures with respect to non-operated properties may result in a reduction or forfeiture of our interests in those properties.

Other companies operated approximately 5% of our production in the fourth quarter of 2006. Our ability to exercise influence over operations for these properties or 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.

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, 2006, approximately 76% of our oil and natural gas revenues were generated from sales to four purchasers, ConocoPhillips, Enserco Energy, Inc., Shell Trading (US) Co. and Gulfmark Energy. 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 may be required to write down the carrying value of our properties and a reduction in our asset values could adversely affect our stock price.

We may be required under full cost accounting rules to write down the carrying value of our properties when oil and natural gas prices decrease or when we have substantial downward adjustments of our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. 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, including the effect of cash flow hedges, 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. Depending on the magnitude of any future impairments, a ceiling test write down could significantly reduce our income or produce a loss. Ceiling test computations use commodity prices prevailing on the last day of the relevant period, making it impossible to predict the timing and magnitude of any future write downs. To the extent our finding and development costs increase, we will become more susceptible to ceiling test write downs in low price environments.

Failure to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could in turn have a material adverse effect on our business and stock price.

Under current SEC rules, we will be required to issue a report assessing the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act as of December 31, 2007 and on an annual basis thereafter. This assessment will require us to document, assess and test our internal controls over financial reporting more comprehensively than we do currently. In addition, our outside auditors will be required to audit and report on our internal controls.

To complete our assessment, we will be required to enhance the documentation of our policies, procedures and internal controls over financial reporting, assess the effectiveness of the design of those controls and test whether those controls are operating as designed. This process, which we are conducting with the assistance of an independent consulting firm, involves considerable time and expense. During the course of our assessment, we may identify material weaknesses that we cannot remediate in time to meet the deadline imposed by SEC rules for certification of our internal controls. A determination that a material weakness exists as of December 31, 2007 or a subsequent date could result in adverse publicity, regulatory scrutiny and a loss of investor confidence in the accuracy and completeness of our financial reports. If our ability to report our financial results in a timely and accurate manner were negatively affected, this could have a material adverse effect on our stock price.

In November 2005, we restated the financial statements included in our Quarterly Reports on Form 10-Q for the first two quarters of 2005. In addition, we have historically operated with a relatively small number of employees in the accounting and financial reporting area. If we had previously conducted an assessment of our internal controls under the standards set forth in Section 404 of the Sarbanes-Oxley Act and related rules, either or both of these factors likely would have led us to conclude that we had one or more material weaknesses in our internal controls. In addition, our outside auditors, in the performance of their 2005 and 2006 audits, concluded that material weaknesses in our internal controls existed in 2005 and 2006. The efforts we have undertaken, or will undertake, to address these issues, or similar issues that may arise or be discovered in the future, may not be successful.

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 68% of our outstanding common stock as of December 31, 2006. 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 certificate of incorporation and bylaws;
- 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, such as our purchase of the membership interests of Marquez Energy in March 2005. Of the aggregate closing payment of $16.6 million made to former members of Marquez Energy in that transaction, Mr. Marquez and David Christofferson, our CFO, received $13.0 million and $1.6 million, respectively. In addition, prior to the completion of our initial public offering, we entered into agreements with the Marquez Trust in connection with dividends of certain real property interests to the trust and to grant certain registration rights to the trust. Mr. Marquez and his wife are the trustees of the Marquez Trust.

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, Timothy Brittan is President of Infinity Oil & Gas, Inc., Glen C. Warren is the President, CFO and a director of Antero Resources Corporation and Mark Snell is CFO of Sempra Energy. In addition, Mac McFarland provides consulting services to various energy-related companies from time to time and Joel Reed is the lead principal of a firm that provides investment banking 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 December 31, 2006, Timothy Marquez beneficially owned approximately 68% of our common stock. As of that date, we had granted options to purchase an aggregate of approximately 4.7 million shares of our common stock to certain of our directors and employees, of which approximately 37% were vested. The Marquez Trust and certain option holders are subject to lock-up agreements with the underwriters of our initial public offering which generally prohibit them from selling shares of common stock without the underwriters' consent. When these lock-up agreements expire in May 2007 (subject to a possible extension of approximately one month in some circumstances), those holders will, subject to compliance with applicable securities laws, be 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, and 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' counsel has announced plans to appeal the ruling. We vigorously defended the actions, and will continue to do so until they are resolved. We also have defense and indemnity obligations to certain other defendants in the actions who have asserted claims for indemnity for events occurring after we acquired the property in 1995. In addition, certain defendants have made claims for indemnity for events occurring prior to 1995, which we are disputing. We cannot predict the cost of defense and indemnity obligations 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") have taken the position that they are 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. The Beverly Hills Unified School District (the "District"), as an additional insured on those policies, brought a declaratory relief action against two of those insurers in Los Angeles County Superior Court. In November 2005, the court ruled in favor of one of the insurers. In February 2007, an appellate court affirmed the decision of the Superior Court. On July 10, 2006, the same Superior Court that ruled in favor of one of the insurers denied a motion for summary judgment brought by another of the insurers against the District on the issue of the insurer's duty to defend. On February 10, 2006, we filed our own 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. That action is ongoing. The policy issued by the insurer that currently is providing defense of the lawsuits contains a pollution exclusion similar to that at issue in the actions brought against the Declining Insurers. However, 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 our 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.

Personal Injury Claim

On March 31, 2006, a complaint was filed in District Court in Madison County, Texas against a subsidiary of ours by the widow of an individual who was killed while working as a gauger/pumper at a well operated by the subsidiary. The case is scheduled to go to trial in August 2007. We plan to vigorously defend this action and believe we have legitimate defenses to all allegations in the suit. We do not currently believe that we are subject to material exposure in association with this lawsuit and no related liability has been recorded in our consolidated financial statements.

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". Our common stock began trading on the New York Stock Exchange on November 17, 2006. Between that date and December 31, 2006, the high and low closing sales prices of our common stock as reported on the New York Stock Exchange Composite Tape were $17.90 and $16.64, respectively.

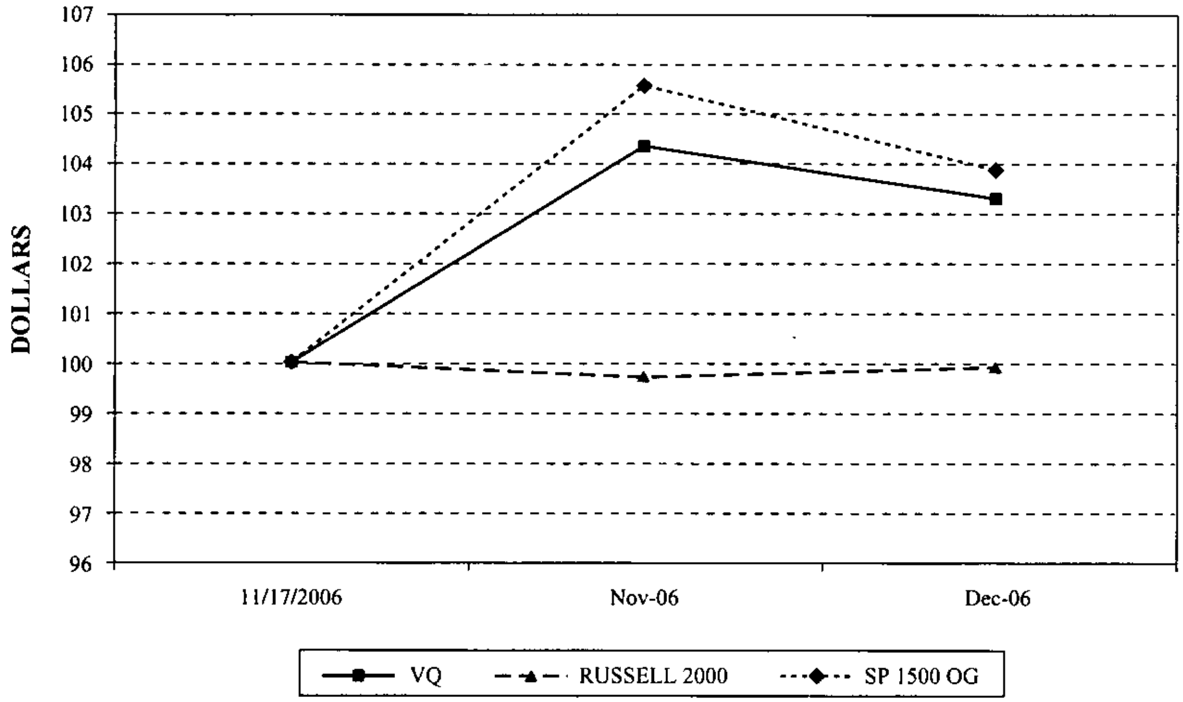
As of February 28, 2007, there were four record holders, and approximately 1,770 beneficial owners, of our common stock.

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, 2006, 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 irrespecive of any general incorporation language in any such filing.



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.

	Year ended December 31,				
	2002 (Predecessor)	2003 (Predecessor)	2004(5)(6) (Predecessor)	2005 (Successor)	2006 (Successor)
Statement of Operations Data:					
Oil and natural gas revenues	$ 93,475	$109,754	$139,961	$191,092	$274,813
Commodity derivative losses	(10,571)	(10,272)	(18,685)	(57,595)	(2,365)
Other revenues(1)	2,580	5,253	5,457	4,456	5,470
Total revenues	85,484	104,735	126,733	137,953	277,918
Production expenses	43,337	45,617	49,567	54,038	87,505
Transportation expense	2,216	2,785	2,915	2,596	3,533
Depreciation, depletion and amortization	19,630	16,161	16,489	21,680	63,259
Accretion of abandonment liability	—	1,401	1,482	1,752	2,542
General and administrative expenses, net of capitalized amounts	16,018	11,632	11,272	16,007	28,317
Litigation settlement expense(2)	—	6,000	—	—	—
Amortization of deferred loan costs	464	370	3,050	1,755	3,776
Interest expense, net	2,343	2,125	2,269	13,673	49,385
Income tax provision (benefit)	500	7,876	16,088	10,300	15,650
Minority interest in Marquez Energy	—	—	95	42	—
Cumulative effect of change in accounting principle, net of tax(3)	—	(411)	—	—	—
Net income	976	11,179	23,506	16,110	23,951
Preferred stock dividends	(8,465)	(8,465)	(7,134)	—	—
Excess of carrying value over repurchase price of preferred stock(4)	—	—	29,904	—	—
Net income (loss) applicable to common equity	$ (7,489)	$ 2,714	$ 46,276	$ 16,110	$ 23,951
Basic earnings (loss) per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ (0.21)	$ 0.07	$ 1.33	$ 0.49	$ 0.71
Cumulative effect of change in accounting principle	—	0.01	—	—	—
Total	$ (0.21)	$ 0.08	$ 1.33	$ 0.49	$ 0.71
Diluted earnings (loss) per common share:					
Income (loss) before cumulative effect of change in accounting principle	$ (0.21)	$ 0.07	$ 0.48	$ 0.49	$ 0.69
Cumulative effect of change in accounting principle	—	0.01	—	—	—
Total	$ (0.21)	$ 0.08	$ 0.48	$ 0.49	$ 0.69

	2002 (Predecessor)	2003 (Predecessor)	2004(5)(6) (Predecessor)	2005 (Successor)	2006 (Successor)
	Year ended December 31,				
Cash Flow Data:					
Cash provided (used) by					
Operating activities	$ 30,284	$ 31,557	$ 43,309	$ 39,931	$ 89,090
Investing activities	(38,916)	(10,531)	(27,990)	(58,695)	(595,204)
Financing activities	14,484	(23,333)	30,979	(26,562)	505,089
Other Financial Data (unaudited):					
Capital expenditures	38,843	9,064	21,829	90,106	194,040
Balance Sheet Data (end of period):					
Cash and cash equivalents	$ 10,724	$ 8,417	$ 54,715	$ 9,389	$ 8,364
Plant, property and equipment, net	159,257	170,663	198,563	233,776	774,253
Total assets	206,101	212,252	298,882	302,558	893,193
Long-term debt, excluding current portion	46,302	22,969	163,542	178,943	529,616
Mandatorily redeemable preferred stock and accrued dividends	86,305	94,770	—	—	—
Stockholders' equity (deficit)	(641)	2,484	48,439 (6)	4,334	190,316

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

(2) Amount comprises settlement costs incurred by us in connection with a lawsuit brought by Mr. Marquez asserting wrongful termination and breach of contract.

(3) The amount shown for 2003 is the cumulative effect of change in accounting principle of $411,000, net of tax. On January 1, 2003, we adopted SFAS 143, "Accounting for Asset Retirement Obligations," which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Pursuant to our adoption of SFAS 143, we recognized a credit during the first quarter of 2003 of $411,000, net of tax, for the cumulative effect of the change in accounting principle. See note 6 to our financial statements.

(4) 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.

(5) Marquez Energy is included in our statements of operations, balance sheet and cash flow data from July 2004, when common control between our company and Marquez Energy was established. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Other Accounting Matters—Acquisition of Marquez Energy."

(6) 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. See note 1 to our financial statements.

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 led to increases in our oil and natural gas production and our year-over-year proved reserves in 2006. Our average net production, which was 11,555 BOE/d in 2005, rose to 17,349 BOE/d in 2006 (calculated as described in footnote 2 to the table included in "—Results of Operations") and was 18,147 BOE/d in the fourth quarter of 2006. We expect further increases in our production in 2007. See "—Trends Affecting Our Results of Operations." Because of the anticipated increases in production and the effect of our hedging program, we expect revenues, not including the effect of non-cash, unrealized derivative gains and losses, to increase in 2007 compared to 2006 even if oil and natural gas prices decline moderately. Our disciplined hedging strategy, which includes the use of collars, swaps and purchased floors, has allowed us to lock in minimum future floor prices we consider attractive on substantial production volumes through December 2010, while often allowing upside participation. See "Qualitative and Quantitative Disclosures About Market Risk" for a summary of our hedging position.

Pursuit of our strategy also led to an increase in our proved reserves in 2006. Our estimated net proved reserves as of December 31, 2006 were 87.9 MMBOE, up 85% from 47.6 MMBOE as of December 31, 2005. Approximately 70% of the increase resulted from acquisitions, in particular the acquisition of TexCal. We believe that we can continue to increase our proved reserves in 2007, subject to the effect of future changes in commodity prices.

In the execution of our strategy, our management is principally focused on increasing our reserves of oil and natural gas and on continuing and strengthening the trend of increasing annual production through exploration, exploitation and development activities and acquisitions and the resolution of operational problems as they arise. Our management is also focused on the risks and opportunities associated with current oil and natural gas prices, which, despite some recent declines, remain generally high compared to longer-term historical averages, and on the goal of maximizing production rates while operating in a safe manner.

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, 2006, were $189.2 million in 2006, up from $83.6 million in 2005, and we expect that they will be approximately $230.0 million in 2007. We expect to spend approximately 24% of the budgeted amount on projects in the Coastal California region, 56% in the Sacramento Basin and 20% in Texas. Included in the budget is $20.0 million for exploration projects, primarily in Coastal California and the Sacramento Basin. The following summarizes other significant aspects of our capital spending program in 2006 and 2007:

Coastal California—Exploitation and Development

	2006	2007
New wells (including unsuccessful)	8(3)	2-6

We expect that our exploitation and development activities in the Coastal California region in 2007 will focus on continued infill development of the Monterey formation using multi-lateral highly deviated wells. We are also evaluating the possibility of expanding waterflooding in the Santa Clara Federal Unit and are finalizing a development plan relating to the possible return of platform Grace to production.

Sacramento Basin—Exploitation and Development

	2006	2007
New wells (including unsuccessful)	60(8)	120+
Recompletions/workovers (including unsuccessful)	34(3)	100

We have six drilling rigs and two workover/completion rigs under contract in the Sacramento Basin as of March 15, 2007 and expect to continue our aggressive drilling program there throughout 2007. Successful wells drilled in the basin in 2006 include one non-operated well; dry holes include one non-operated well and one that failed due to mechanical problems that prevented the well from reaching the geologic objective. Of the 60 wells drilled in the basin in 2006, 47 were drilled to non-proved locations and are therefore considered "exploratory wells" as defined in SEC Regulation S-X.

Texas—Exploitation and Development

	2006	2007
New wells (including unsuccessful)	2(0)	6
Recompletions/workovers (including unsuccessful)	142(0)	100-200

In 2007, we expect to continue the recompletion and workover program we began in the Hastings complex following the completion of the TexCal acquisition. This program contributed to a 38% increase in average net production from the complex from March 2006 to December 2006.

Higher Impact Exploration Activities. In addition to the exploitation and development activities described above, we devoted approximately $19.4 million to higher impact exploration wells in 2006. We completed five such wells during 2006, of which two were productive and three were dry holes. In 2007, we expect to drill approximately ten higher impact exploration wells, including six in the Sacramento Basin, three in Coastal California and one in Texas.

The aggregate levels of capital expenditures for 2007, and the allocation of those expenditures, are dependent on a variety of factors, including the availability of capital resources to fund the expenditures, the availability of service contractors and equipment, permitting issues, weather, limits on the number of activities that can be conducted at any one time on our offshore platforms 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 the estimates described above.

Acquisitions and Divestitures

TexCal Transaction. We acquired TexCal on March 31, 2006 for $456.8 million in cash. According to a reserve report prepared by DeGolyer & MacNaughton, as of December 31, 2005, TexCal had proved reserves of 31.4 MMBOE. The acquisition is consistent with our strategy of acquiring large, mature fields with established reserves and significant exploitation and development potential, and provided us with substantial additions to our multi-year drilling inventory. TexCal acquired all of its properties in October 2004 from Tri-Union Development Corporation, which was then a debtor in proceedings under Chapter 11 of the U.S. bankruptcy code. In part due to the circumstances leading to the Tri-Union bankruptcy, capital expenditures devoted to the properties were limited in the years preceding the TexCal transaction. In order to finance the $456.8 million 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.

Acquisition of Marquez Energy. We completed our acquisition of Marquez Energy, a Colorado limited liability company majority owned and controlled by our CEO, Timothy Marquez, on March 21, 2005. According to a reserve report prepared by NSAI, Marquez Energy had proved reserves of approximately 2.0 MMBOE as of December 31, 2004. The purchase price for the membership interests in Marquez Energy was $16.8 million (including a $2.0 million deposit paid in 2004). Pursuant to the purchase agreement, NSAI conducted a supplemental evaluation of the Marquez Energy properties as of December 31, 2005 and 2006. If either report had attributed proved reserves to the Marquez Energy properties in excess of those reflected in NSAI's original report, an additional payment would have been made to the former holders of interests in Marquez Energy. No additional payment was due as a result of either report and all payment obligations to the former holders have now been satisfied.

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.

Sale of Big Mineral Creek. On March 31, 2005, we completed the sale of our Big Mineral Creek field, located in Grayson County, Texas, to BlackWell Energy Group, LLC for $44.6 million. Average net production at the field was approximately 547 BOE/d in the first quarter of 2005. Pursuant to Section 1031 of the Internal Revenue Code, we effected a like-kind exchange of a portion of the Big Mineral Creek field representing approximately $15.0 million of the total sale price for certain Marquez Energy properties and properties acquired from third parties. The like-kind exchange provisions resulted in the deferral of a portion of income taxes related to the gain on sale. We did not recognize a gain on sale for financial reporting purposes, but applied the net sales proceeds to reduce the capitalized costs of our oil and natural gas properties in accordance with our full-cost accounting method.

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 in and around our existing core areas of operations, including several transactions in both 2005 and 2006. In addition, in the fourth quarter of 2005, we purchased the Union Island pipeline, a 32-mile natural gas pipeline that runs from the Union Island field to a location near Pittsburg, California, for $6.1 million.

Trends Affecting our Results of Operations

Expected 2007 Production. We expect that implementation of our capital expenditure program in 2007 will result in a significant increase in our average net production for the year relative to 2006. We expect that average net production in the first quarter of 2007 will be similar to the average for the fourth quarter of 2006, and that significant increases will occur in second, third and fourth quarters of 2007. We will focus on growing production in the Sacramento Basin and the Hastings complex, and expect to maintain production from the majority of our other properties at rates substantially consistent with year-end 2006 levels. We are pursuing a multi-year drilling program in the Sacramento Basin, and have six rigs operating in the basin as of March 15, 2007. Based on anticipated rig availability, we plan to drill more than 120 wells in the basin in 2007. We expect that additional completion rigs will be available to us in the basin in the second quarter of 2007, and that this will allow us to increase the number of recompletions performed there and reduce a backlog of wells awaiting completion. This should allow us to increase the rate of production growth there. In the Hastings complex, we are actively recompleting and working over wells, and have four workover rigs in the field as of March 15,

2007. We expect to continue our recompletion and workover program in the field throughout 2007. The acquisitions we expect to complete in the second quarter should also contribute to the expected increase for the year. Our expectations with respect to future production rates are subject to a number of uncertainties, including those associated with the availability and cost of rigs and third party services, oil and natural gas prices, the potential for mechanical problems, permitting issues, drilling success rates, the availability of acceptable delivery and sales arrangements with respect to oil production from the South Ellwood field, pipeline capacity, the accuracy of our assumptions regarding the sustainability of historical growth rates, our ability to complete pending acquisitions, weather and other factors, including those referenced in "Risk Factors."

Production Expenses. Production expenses increased to $15.09 per BOE in 2006 from $12.81 per BOE in 2005. The increase was primarily attributable to substantial remedial work we conducted in the Hastings complex following the acquisition of TexCal and the fact that production volumes in the third quarter of 2006 were reduced due to maintenance projects in our South Ellwood and Willows fields. We expect to significantly reduce the amount of the remedial work conducted in the Hastings complex after the end of the second quarter of 2007. Also, we are in the process of adding production from our lower operating cost gas wells in the Sacramento Basin. These factors are expected to result in our 2007 production expenses trending downward on a per BOE basis. Our expectations with respect to future per-unit expenses are based in part on the projected increases in our production described in the preceding paragraph and are subject to numerous risks and uncertainties, including those described and referenced therein.

General and Administrative Expenses. In order to manage and maximize our growth, we have been increasing our professional staff, and this has resulted in increased general and administrative expenses. The TexCal transaction has also increased those expenses. In the last three quarters of 2006, we incurred substantial expenses in connection with the integration of TexCal as well as various systems conversion expenses. We also incurred $2.8 million in non-cash compensation expenses related to the implementation of FAS 123R in 2006, and did not incur any such expenses in 2005. Primarily as a result of these factors, our general and administrative expenses increased from $3.79 per BOE in the 2005 to $4.88 per BOE in 2006. Integration expenses relating to the TexCal acquisition were substantially complete by year-end 2006, and systems conversion expenses are expected to be reduced in 2007. On a per BOE basis, we expect that our general and administrative expenses, excluding expenses relating to FAS 123R and capitalized general and administrative expenses, will decline in 2007 relative to 2006. As with production expenses, our expectations in this regard are based in part on our projected increases in production, which are subject to numerous risks and uncertainties. In addition, we have not to date fully quantified the expenses we expect to incur with respect to Sarbanes-Oxley Act compliance, and those expenses may be significant.

Unrealized Commodity Derivative Gains and Losses. Rising oil and natural gas prices created substantial unrealized commodity derivative losses in 2005, and fluctuating oil prices and lower natural gas prices led to unrealized commodity derivative gains in 2006. These unrealized gains and losses resulted from mark-to-market valuations for non-highly effective or ineffective portions of our derivative positions 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 2007 and subsequent years.

Internal Control Over Financial Reporting

In November 2005, we restated the financial statements included in our Quarterly Reports on Form 10-Q for the first two quarters of 2005. In addition, we have historically operated with a relatively small number of employees in the accounting and financial reporting area. If we had previously conducted an assessment of our internal controls under the standards set forth in Section 404 of the Sarbanes-Oxley Act and related rules, either or both of these factors likely would have led us to conclude that we had one or more material weaknesses in our internal controls. In addition, our outside auditors, in the performance of their 2005 and 2006 audits, concluded that material weaknesses in our internal controls existed in 2005 and 2006. We have taken a variety of actions to address these issues, including the adoption of more extensive accounting controls and financial review procedures and the hiring of additional accounting staff. A substantial part of our efforts in this regard in 2006 focused on the design of a more comprehensive system of internal controls. We expect to focus on the implementation and testing of this system in 2007.

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.

	Year ended December 31,		
	2004(1)	2005(1)	2006(2)
Production Volume			
Natural gas (MMcf)	5,826	7,588	14,314
Oil (MBbls)	3,101	2,953	3,411
MBOE	4,072	4,218	5,797
Daily Average Production Volume			
Natural gas (Mcf/d)	15,918	20,789	44,346
Oil (Bbls/d)	8,472	8,090	9,958
BOE/d	11,125	11,555	17,349
Oil Price per Bbl Produced (in dollars)			
Realized price	$34.69	$45.66	$55.92
Realized commodity derivative loss and amortization of commodity derivative premiums	(5.47)	(7.46)	(8.38)
Net realized	$29.22	$38.20	$47.54
Natural Gas Price per Mcf Produced (in dollars)			
Realized price	$ 5.77	$ 7.45	$ 6.04
Realized commodity derivative gain (loss) and amortization of commodity derivative premiums	(0.11)	(0.11)	0.36
Net realized	$ 5.66	$ 7.34	$ 6.40
Average Sale Price per BOE(3)	$30.42	$39.55	$44.13
Expense per BOE			
Production expenses(4)	$12.17	$12.81	$15.09
Transportation expenses	$ 0.72	$ 0.62	$ 0.61
Depreciation, depletion and amortization	$ 4.05	$ 5.14	$10.91
General and administrative expense, net(5)	$ 2.77	$ 3.79	$ 4.88
Interest expense, net(5)	$ 0.56	$ 3.24	$ 8.52

(1) Amounts shown include Marquez Energy from July 1, 2004. See "—Other Accounting Matters—Acquisition of Marquez Energy."

(2) 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.

(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) Production expenses are comprised of oil and natural gas production expenses and production taxes.

(5) Net of amounts capitalized.

Comparison of Year Ended December 31, 2006 to Year Ended December 31, 2005

Oil and Natural Gas Revenues. Oil and natural gas revenues increased $83.7 million (44%) to $274.8 million in 2006 from $191.1 million in 2005. The increase was primarily due to production attributable to the TexCal acquisition and higher realized oil prices, partially offset by a 1% decrease in production from other Venoco properties. The decline in production volumes from other Venoco properties was the result of (i) the effect of our sale, on March 31, 2005, of the Big Mineral Creek field (which averaged net production of 547 BOE/d in the first quarter of 2005), (i) high initial production rates in early 2005 from new offshore oil wells which had recently come on line at that time and (iii) the effect of maintenance projects in the third quarter and early fourth quarter of 2006, which limited production volumes in those periods.

Oil revenues increased by $53.7 million in 2006 (40%) to $188.3 million compared to $134.6 million in 2005. Oil production rose 16%, with production of 3,411 MBbl in 2006 compared to 2,953 MBbl in 2005. The production increase was attributable to the TexCal properties, partially offset by an 8% decline in production volumes from other Venoco properties. The decline in production from other Venoco properties resulted from the factors discussed above. Our average realized price for oil before realized hedging losses increased $10.26 (22%), to $55.92 per Bbl for the period. We hedged 70% of our oil production during the period (excluding floors), resulting in realized hedging losses of $8.38 per Bbl. We also had unrealized hedging gains of $3.87 per Bbl during the year.

Natural gas revenues increased $30.0 million in 2006 (53%) to $86.5 million compared to $56.5 million in 2005. Natural gas production increased 89%, with production of 14,314 MMcf compared to 7,588 MMcf in 2005. The majority of the increase was due to production attributable to the TexCal acquisition. Approximately 15% of the increase resulted from increased production from other Venoco properties. The increased production from other Venoco properties relates to our ongoing field development activities. Our average realized price for natural gas before realized hedging gains decreased $1.41 (19%) to $6.04 per Mcf for the period. We hedged 49% of our natural gas production during the period (excluding floors), resulting in realized hedging gains of $0.36 per Mcf. We also had unrealized hedging gains of $0.55 per Mcf during the year.

Commodity Derivatives and Other Revenues. Total commodity derivative losses decreased $55.2 million (96%) from $57.6 million in 2005 to $2.4 million in 2006. Realized commodity derivative losses decreased $5.4 million (26%) to $15.3 million in 2006 compared with $20.7 million in 2005. Amortization of derivative premiums increased $3.5 million (74%) from $4.7 million in 2005 to $8.2 million in 2006. Unrealized commodity derivative gains were $21.1 million in 2006, compared to net unrealized losses of $32.2 million in 2005. The changes in commodity derivative gains (losses) are due to the effect changes in market prices of oil and natural gas have on our net sales, in the case of realized losses, and the effect of mark to market pricing adjustments on the carrying value of our derivative positions, in the case of unrealized losses. The decrease in total commodity derivative losses in 2006 resulted primarily from the non-recurrence in 2006 of the significant increases in commodity prices that occurred in 2005. Other revenue increased 23%, from $4.5 million in 2005 to $5.5 million in 2006. This increase was primarily due to revenues of $2.3 million from a pipeline we acquired in the fourth quarter of 2005.

As a result of the foregoing factors, total revenues increased $140.0 million (101%) to $277.9 million in 2006, compared to $138.0 million in 2005. Of the total revenue increase, $53.3 million, or 38% of the increase, was attributable to the change in unrealized derivative gains (losses).

Production Expenses. Production expenses increased $33.5 million (62%) to $87.5 million in 2006 from $54.0 million in 2005. The increase was primarily due to production expenses attributable to the TexCal acquisition and a 9% increase in production expenses from other Venoco properties. The increase in production expenses for other Venoco properties relates to an increase in the number of producing wells, normal variances of timing of production expenses, including expenses relating to periodic maintenance projects, and increased costs of third party services. On a per unit basis, costs increased $2.28 per BOE, from $12.81 per BOE in 2005 to $15.09 per BOE in 2006. A significant part of this increase was attributable to remedial work projects performed in the Hastings complex in the second half of the year. Per unit production expenses attributable to the TexCal properties rose from $14.02 per BOE in 2005 to $17.34 per BOE in 2006 primarily as a result of those projects. In addition, production expenses on a per unit basis for other Venoco properties increased 11% in 2006 due primarily to increased costs of services.

Transportation Expenses. Transportation expenses increased 36%, from $2.6 million in 2005 to $3.5 million in 2006. This was primarily attributable to volume increases. On a per BOE basis, transportation expenses decreased $0.01 per BOE, from $0.62 per BOE in 2005 to $0.61 per BOE in 2006.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $41.6 million (192%) to $63.3 million in 2006 from $21.7 million in 2005. DD&A expense rose $5.77 per BOE, from $5.14 per BOE in 2005 to $10.91 per BOE in 2006. The increase was primarily due to a higher depletion expense resulting from the increase in the value of oil and natural gas properties obtained in the TexCal acquisition and an increase in future development costs.

Accretion of Abandonment Liability. Accretion expense increased $0.8 million (45%) to $2.5 million in 2006 from $1.8 million in 2005. The increase was due to accretion from the acquired TexCal properties and from new wells drilled and completed in 2006.

General and Administrative (G&A). G&A expense increased $12.3 million (77%) to $28.3 million in 2006 from $16.0 million in 2005. G&A expense rose $1.09 per BOE (30%), from $3.79 per BOE in 2005 to $4.88 per BOE in 2006. We have increased the depth of our organization in order to position us for growth and to more effectively exploit our asset base by adding professional, technical and support staff, which has contributed to the increase in G&A expenses. Other significant components of the increase include $2.8 million in non-cash costs relating to FAS 123R in 2006, which represented 28% of the increase, and $0.5 million in expenses related to TexCal transition and integration activities that were completed in 2006. In addition, we incurred $1.0 million in direct costs related to Sarbanes-Oxley compliance activities and other indirect costs for internal systems and process conversions intended to position us to more efficiently comply with the Sarbanes-Oxley Act in the future.

Interest Expense and Amortization of Deferred Loan Costs. Interest expense, net of interest income and capitalized interest, increased $35.7 million (261%) to $49.4 million in 2006 from $13.7 million in 2005. Amortization of deferred loan costs increased $2.0 million (115%) to $3.8 million in 2006 from $1.8 million in 2005. The changes were primarily due to debt incurred in late March 2006 to acquire TexCal.

Income tax expense. Income tax expense in 2006 was $15.6 million compared to $10.3 million for 2005. The change was due to an increase in income. Our effective tax rate decreased from 40.0% for 2005 to 38.6% for 2006 due to an increase of business activity in lower taxing jurisdictions.

Net Income. Net income for 2006 was $24.0 million as compared to net income of $16.1 million in 2005.

Comparison of Year Ended December 31, 2005 to Year Ended December 31, 2004

Oil and Natural Gas Revenues. Oil and natural gas revenues increased $51.1 million (37%) to $191.1 million for the year ended December 31, 2005 from $140.0 million for 2004. The increase was primarily attributable to rising oil and natural gas prices, which added $43.8 million to oil and natural gas revenues (87%), and an increase in natural gas production, which added $13.1 million to natural gas revenues (26%). Partially offsetting these increases was a decrease in oil production, which decreased oil revenues by $6.8 million (13%).

Oil revenues increased by $28.2 million in 2005 (27%) to $134.6 million from $106.4 million in 2004. Oil production fell 5%, with production of 2,953 MBbl in 2005 compared to 3,101 MBbl in 2004, primarily due to the sale of our Big Mineral Creek field. Our average realized price for oil increased $10.97 (32%) to $45.66 per Bbl for the year. We hedged 71% of our oil production during the year (excluding floors), resulting in realized hedging losses of $7.46 per Bbl and unrealized hedging losses of $10.50 per Bbl. Total hedging losses on oil were $17.96 per Bbl for the year.

Natural gas revenues increased $22.9 million in 2005 (68%) to $56.5 million from $33.6 million in 2004. Natural gas production rose 30%, with production of 7,588 MMcf compared to 5,826 MMcf in 2004. Our average realized price for natural gas increased $1.68 (29%) to $7.45 per Mcf for the year. We hedged 15% of our natural gas production during the year (excluding floors), resulting in realized hedging losses of $0.11 per Mcf and unrealized hedging losses of $0.49 per Mcf. Total hedging losses on natural gas were $0.60 per Mcf for the year.

Total revenues increased $11.2 million (9%) to $138.0 million in 2005 from $126.7 million in 2004. This increase primarily resulted from the 37% increase in oil and natural gas revenues being partially offset by an increase in total commodity derivative losses. Total commodity derivative losses increased $38.9 million (208%) from $18.9 million in 2004 to $57.6 million in 2005. Realized commodity derivative losses increased $3.1 million (17%) to $20.7 million in 2005 compared with $17.6 million in 2004. Amortization of derivative premiums increased from zero in 2004 to $4.7 million in 2005. Unrealized commodity derivative losses were $1.1 million in 2004, compared to $32.2 million in 2005. The increase in total commodity derivative losses in 2005 was caused primarily by the increases in commodity prices that occurred during the year relative to our derivative positions.

Production Expenses. Production expenses increased $4.4 million (9%) to $54.0 million in 2005 from $49.6 million in 2004. This increase was primarily due to increased field activity in 2005 combined with unanticipated expenses associated with the resolution of mechanical problems at a well in the South Ellwood field and periods of limited production capacity due to platform equipment repair and well maintenance. These unanticipated expenses occurred concurrent with a period of reduced production, which resulted in an increase in the per unit costs in 2005 of $0.64 per BOE (from $12.17 per BOE in 2004 to $12.81 per BOE in 2005).

Transportation Expenses. Transportation expenses fell by $0.3 million (11%) to $2.6 million in 2005 from $2.9 million in 2004. On a per BOE basis, transportation expenses decreased $0.10 (14%) to $0.62 per BOE from $0.72 per BOE in 2004.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $5.2 million (31%) to $21.7 million in 2005 from $16.5 million in 2004. DD&A expense rose $1.09 per BOE on a per unit basis, from $4.05 per BOE in 2004 to $5.14 per BOE in 2005. This was due to changes in estimated future development costs and development costs incurred in 2005 which had the collective effect of increasing the depletion rate per unit. Overall DD&A expense also rose due to increased production volumes.

Accretion of Abandonment Liability. Accretion expense rose $0.3 million (18%), to $1.8 million in 2005 from $1.5 million in 2004. The increase was due to an increase in abandonment liability associated with additional wells.

General and Administrative (G&A). G&A expense increased $4.7 million (42%) to $16.0 million in 2005 from $11.3 million in 2004. The largest single component, representing 12% of the increase, is the accrual in December 2005 of a $1.3 million pool for bonuses to be paid to office and administrative staff, including officers, in the second quarter of 2006. This was due to the implementation of more structured and formalized plans relative to prior years, when bonus amounts were less predictable prior to the time of payment. Office and administrative bonuses, including officers' bonuses, determined, accrued and paid in the second quarter of 2005 totaled $0.8 million. The total increase in G&A in 2005 also resulted from increases in technical staff, higher professional fees related to accounting and information technology systems conversions and enhancements and the inclusion of expenses of Marquez Energy for all of 2005 as compared to only six months in 2004.

Interest Expense and Amortization of Deferred Loan Costs. Interest expense, net of interest income and capitalized interest, increased $11.4 million (503%) to $13.7 million in 2005 from $2.3 million in 2004. The change resulted primarily from the increase in indebtedness associated with the issuance of $150.0 million of our senior notes in December 2004. Amortization of deferred loan costs decreased $1.3 million in 2005 compared to 2004. The decrease in amortization was primarily due to a $2.2 million write-off of deferred loan costs in December 2004 related to a reduction in the borrowing capacity under our credit agreement.

Income tax expense. Income tax expense in 2005 of $10.3 million represented a decrease of $5.8 million (36%) from $16.1 million in 2004. The decrease was primarily due to lower taxable income in the period.

Net Income. Net income for 2005 was $16.1 million, compared to net income of $23.5 million in 2004. As discussed above, the largest factors causing the change were the substantial increase in unrealized derivative losses and increased interest expense, partially offset by an increase in oil and natural gas revenues.

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

	Year ended December 31,		
	2004	2005	2006
	(Predecessor)	(Successor) (in thousands)	(Successor)
Cash provided by operating activities	$ 43,309	$ 39,931	$ 89,090
Cash used in investing activities	(27,990)	(58,695)	(595,204)
Cash provided by (used in) financing activities	30,979	(26,562)	505,089

Net cash provided by operating activities was $89.0 million in 2006 compared with $39.9 million in 2005. Cash flows from operating activities during 2006 were favorably impacted by production attributable to the TexCal acquisition and a $14.9 million decrease in cash paid for premiums on derivative contracts compared to 2005.

Net cash used in investing activities was $595.2 million in 2006. The primary investing activities in 2006 include $447.5 million paid in cash to acquire TexCal (net of TexCal cash) and $185.2 million, not including amounts accrued and unpaid at December 31, 2006, in expenditures for oil and natural gas properties, including acquisitions of additional interests near our core properties. Sources of cash from investing activities include $37.5 million received in connection with the Denbury option agreement and $8.9 million in proceeds from sales of other oil and natural gas properties.

Net cash provided by financing activities was $505.1 million in 2006. Proceeds from long-term debt in 2006 included $350.0 million borrowed under the 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 million in loan costs. Net proceeds from our initial public offering of common stock 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 under the revolving credit facility of $47.5 million were used to fund capital expenditures and working capital needs.

Net cash provided by operating activities was $39.9 million in 2005 compared with $43.3 million in 2004. Cash flows from operating activities were negatively impacted primarily by an $11.9 million increase in payments of net premiums on derivative contracts, an $11.4 million increase in interest costs, a $5.3 million increase in realized commodity derivative losses, a $3.4 million increase in the cash portion of operating and general and administrative expenses and a $4.5 million increase in oil and natural gas production expenses. These factors were partially offset by a $51.1 million increase in oil and natural gas sales, resulting from increased production, the acquisition of Marquez Energy and higher commodity prices.

Net cash used in investing activities in 2005 was $58.7 million and consisted primarily of $88.3 million used to develop and acquire oil and natural gas properties other than those of Marquez Energy (comprised of $100.2 million in costs incurred less $11.9 million in accrued amounts payable at December 31, 2005) and $14.6 million used to acquire Marquez Energy, which uses were offset primarily by $44.6 million in net proceeds from the sale of oil and natural gas properties.

Net cash used in financing activities was $26.6 million in 2005 and related primarily to the payment of a $35.0 million dividend to our then-sole stockholder, $5.3 million used to purchase the interests of minority stockholders and principal repayments on long-term debt of $43.7 million, partially offset by $59.0 million in new borrowings under our credit agreement.

Net cash used in investing activities was $28.0 million in 2004, of which $16.3 million related to capital expenditures for drilling and reworking wells, facilities and related costs. Net cash provided by financing activities in 2004 was $31.0 million, including $272.4 million in proceeds from long term debt, primarily consisting of $146 million in net proceeds from the issuance of our senior notes, $100.7 million in amounts borrowed under our credit agreement and $10.0 million in financing for our new office building. Cash used in financing activities primarily included $159.7 million in repayment of amounts borrowed under our credit agreement and our prior credit facility and $72.0 million for the repurchase of our preferred stock.

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 in 2007 will be approximately $230.0 million. In addition, we expect to spend an aggregate of approximately $106.0 million to complete the acquisitions described in "Business and Properties—Recent Developments—Asset Acquisitions." As a general matter, our strategy is to finance our exploration, exploitation and development capital expenditures primarily with cash flow from operations and to use additional borrowings under our revolving credit facility only for short-term working capital needs, for acquisitions or in other special situations. However, the extent to which we follow this strategy in any given period is subject to a number of factors, including uncertainties associated with subsequent changes in commodity prices and the possibility of additional significant acquisitions, and considerations relating to our overall debt level. In some prior periods, we used borrowings under our revolving credit facility to fund a significant portion of our exploration, exploitation and development capital expenditures and we may do so in the future. As of March 30, 2007, approximately $72.0 million was outstanding under the revolving credit facility, which has an aggregate maximum loan amount of $300.0 million and currently has a borrowing base of $230.0 million. The borrowing base will be redetermined twice each year in May and November, based on reserve reports prepared as of January 1 and July 1 of the relevant year. An amendment to the credit agreement entered into in March 2007 resulted in the elimination of certain restrictive covenants regarding capital expenditures and acquisitions.

We entered into the revolving credit facility and a second lien term loan facility to finance our acquisition of TexCal. On March 30, 2006, we borrowed $350.0 million pursuant to the second lien term loan facility. On March 31, 2006, we borrowed $119.5 million under the revolving credit facility. Principal on the second lien term loan facility is payable on March 30, 2011 and principal on the revolving credit facility is payable on March 30, 2009. The revolving credit facility and the second lien term loan facility are secured by liens on substantially all of our oil and natural gas properties and other assets, including the stock of all of our subsidiaries, and they are unconditionally guaranteed by each of our subsidiaries other than Ellwood Pipeline, Inc. Pursuant to mandatory prepayment provisions set forth in the credit facilities, substantially all of the proceeds of asset sales and certain additional borrowings, and up to 50% of the proceeds of equity issuances, must be used to reduce amounts outstanding under the revolving credit facilty or offered as prepayments to lenders under the second lien term loan facility. We may from time to time make optional prepayments on outstanding loans, subject to the satisfaction of certain conditions. Under the second lien term loan facility, optional prepayments made prior to March 31, 2007 are subject to a prepayment premium of 2%, and optional prepayments made from April 1, 2007 through March 31, 2008 are subject to a prepayment premium of 1%. Lenders under the second lien term loan facility are entitled to decline mandatory offers to prepay indebtedness under that facility, a right that has been exercised by a significant number of those lenders. As a result, proceeds of offerings and asset sales have largely been applied to reduce outstanding borrowings under the revolving credit facility, therefore increasing amounts available for future borrowing. Amounts prepaid under the second lien term loan facility may not be reborrowed.

Loans made under both facilities are designated, at our option, as either "Base Rate Loans" or "LIBO Rate Loans." Base Rate Loans under the revolving credit facility 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) a margin ranging from 0.75% to 1.50%, based upon the percentage of the total borrowing base represented by outstanding borrowings. LIBO Rate Loans under the revolving credit facility bear interest at (i) LIBOR plus (ii) a margin ranging from 2.25% to 3.00%, also 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.

Base Rate Loans under the second lien term loan facility bear interest at a floating rate equal to (i) the greater of the administrative agent's announced base rate and the overnight federal funds rate plus 0.50% plus (ii) 3.50%. LIBO Rate Loans under the second lien term loan facility bear interest at LIBOR plus 4.50%.

The agreements governing the revolving credit facility and the second lien term loan facility contain customary representations, warranties, events of default, indemnities and covenants, including operational covenants that restrict our ability to incur indebtedness or grant liens on our assets and financial covenants that require us to maintain specified ratios of EBITDA to interest expense, current assets to current liabilities, debt to EBITDA and PV-10 to total debt. Our revolving credit agreement also requires that we maintain derivative contracts covering a minimum of 50% of our anticipated oil and gas production through 2010. The ratios required to be met in order to remain in compliance with our financial covenants change at specified times over the duration of the loans. On March 31, 2007, the required ratio of EBITDA to interest expense changed from 2.5:1 to 3:1 and the maximum permitted ratio of debt to EBITDA changed from 4.5:1 to 4:1. These covenant levels will remain in effect until September 30, 2007, at which time new EBITDA to interest expense and debt to EBITDA ratios come into effect that will require higher levels of financial performance and/or reduced indebtedness. We were in compliance with all of the financial covenants set forth in our debt agreements as of December 31, 2006. The revolving credit agreement and the second lien term loan agreement prohibit us from paying dividends on our common stock.

As of March 30, 2007, amounts outstanding under the credit facilities bore interest at a weighted average rate of 9.56%. As discussed in "Quantitative and Qualitative Disclosures About Market Risk," our debt service obligations under the credit facilities may increase if market interest rates rise.

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. The notes are guaranteed by all of our subsidiaries other than Ellwood Pipeline, Inc. The notes were issued as unsecured obligations subject to a covenant requiring that they be equally and ratably secured in the event of certain secured borrowings that do not constitute "permitted liens" (as defined), and are currently secured.

We may redeem the notes after December 15, 2008, initially at a redemption price equal to 104.375% of the principal amount. In addition, before December 15, 2008, we may redeem all or part of the notes at a specified "make-whole" price, and before December 15, 2007, we may redeem up to 35% of the notes with the net proceeds of certain public or private equity offerings at a redemption price of 108.75% of the principal amount of the notes. Upon the occurrence of a change of control of our company, each holder of 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.

Because we must dedicate a substantial portion of our cash flow from operations to the payment of interest on our debt, 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 performance 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 or restructure our debt. If cash flow from operations does not meet our expectations, we may reduce the expected level of capital expenditures and/or fund a portion of the expenditures using borrowings under our revolving credit facility or other sources. If we seek additional capital to pursue our capital expenditure plan, make acquisitions or for other reasons, we may do so through traditional reserve base borrowings, joint venture partnerships, asset sales, offerings of debt and equity securities or other means. 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 the mandatory prepayment provisions in our credit facilities described above, our ability to respond to a shortfall in our expected liquidity by selling assets, issuing equity securities 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 or finance the capital expenditures necessary to replace our reserves. Although we believe that our cash flow from operations, supplemented as needed by amounts available under the revolving credit facility, will provide sufficient liquidity for us to execute our current capital expenditure plans and to complete currently planned acquisitions, we are considering restructuring our debt in order to gain additional financial and operational flexibility, and we may engage in one or more financing transactions in connection with such a restructuring.

Commitments and Contingencies

As of December 31, 2006, 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	$ 3,557	$31,417	$498,199	$ —	$533,173
Interest on senior notes	13,125	26,250	25,156	—	64,531
Rental of office space	1,837	3,849	3,741	11,419	20,846
Total	$18,519	$61,516	$527,096	$11,419	$618,550

(1) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations. Our total asset retirement obligations were $42.0 million at December 31, 2006.

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 accumulation of oil and natural gas that is 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, 2006 estimate of net proved oil and natural gas reserves totaled 87,932 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 one percent lower. In addition, our proved reserves are concentrated in a relatively small number of wells. At December 31, 2006, 16% of our proved reserves were concentrated in our twelve 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 capitalized 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, 2006 would have resulted in an increase of approximately $1.34 per BOE in our depletion expense rate during 2006. 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 for impairment either individually or on an aggregated basis using a comparison of the carrying values of the unproved properties to net future cash flows.

Capitalized costs of oil and natural gas 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, including the effects of cash flow hedges, and requires a write down for accounting purposes if the ceiling is exceeded. At December 31, 2006, our net capitalized costs did not exceed the ceiling. We last incurred a write down due to the ceiling test at the end of 1998, at which time our net capitalized cost exceeded the ceiling by $6.5 million, net of income tax effects, and we recorded a write down of our oil and natural gas properties in that amount.

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 depreciation 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 6% and 8%. 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 not recognized a valuation allowance against our net deferred taxes because we believe that it is more likely than not that the net deferred tax assets will be realized based on estimates of our future operating income.

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 from third parties, 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.

Other Accounting Matters

Push-Down Accounting

During 2004, our Chairman and CEO, Timothy Marquez, increased his beneficial ownership of our outstanding stock from 41% to 100%. Mr. Marquez acquired 53% of the shares of common stock then outstanding from two of our former officers and their respective affiliates in a transaction that closed on July 12, 2004. On December 22, 2004, we merged with a corporation the sole stockholder of which was the Marquez Trust. In the merger, the trust acquired the remaining 6% of our common stock and as a result now owns all of our outstanding common stock.

As a result of Mr. Marquez obtaining control of over 95% of the common stock on December 22, 2004, SEC Staff Accounting Bulletin No. 54 requires the acquisition by Mr. Marquez to be "pushed-down," meaning our post-transaction condensed consolidated balance sheet and the condensed consolidated statements of operations and cash flows reflect a new basis of accounting. The pre-transaction condensed consolidated statements of operations and cash flows are presented on a historical basis.

Acquisition of Marquez Energy

Because Marquez Energy was a company under common control since July 12, 2004, our financial statements and production information include Marquez Energy from July 1, 2004 (results during the period between July 1 and July 12, 2004 were *de minimis*). The acquisition was accounted for in a manner similar to a pooling of interests whereby the historical results of Marquez Energy were combined with our financial results. Accordingly, of the total purchase price for Marquez Energy of $16.8 million, $9.8 million was charged to equity for the excess of the purchase price over Mr. Marquez' historical basis (net of deferred tax assets of $3.7 million), oil and natural gas properties were written up by $3.7 million to fair value for amounts paid to minority interests, and equity was credited for $0.4 million to eliminate the minority interests in Marquez Energy. The production information included in this report also includes Marquez Energy from July 1, 2004. However, Marquez Energy's proved reserves as of December 31, 2004 are not included in our proved reserves as of that date.

Recent Accounting Pronouncements

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation is effective for fiscal years beginning after December 15, 2006. We are currently evaluating the effect that the adoption of FIN 48 will have on our consolidated financial statements and have not yet determined whether the adoption will have a material impact on our consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. The standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "*Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*" ("SAB 108"). SAB 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. The staff of the SEC believes that registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 is effective for the first annual period ending after November 15, 2006 and provides for a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006 for errors that were not previously deemed material but are deemed material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on our consolidated financial position or results of operations.

PV-10 Value and Reserve Replacement Costs

PV-10 Value

The present value of future net cash flows (PV-10 value) is a non-GAAP measure because it excludes income tax effects. Management believes that before-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 value 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 value as of the dates shown (in thousands):

	December 31,		
	2004(1)	2005(2)	2006(3)
Standardized measure of discounted future net cash flows	$404,052	$565,385	$ 819,302
Add: Present value of future income tax discounted at 10%	249,026	328,445	301,774
PV-10 value	$653,078	$893,830	$1,121,076

(1) Based on unescalated prices of (i) $40.25 per Bbl for oil and natural gas liquids, adjusted for quality, transportation fees and regional price differentials and (ii) $6.18 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $10.08 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

(3) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $5.64 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

Reserve Replacement Costs

We discuss our historical reserve replacement costs in "Business and Properties—Our Strengths—Attractive Reserve Replacement Costs." We define the term "reserve replacement cost" to mean an amount per BOE equal to the sum of all costs incurred relating to oil and natural gas property acquisition, exploitation, development and exploration activities (as reflected in our year-end financial statements for the relevant year) divided by the sum of all additions and revisions to estimated proved reserves, including reserve purchases. The calculation of reserve additions for each year is based upon the reserve report of our independent engineers as of the end of the relevant period, and includes, where applicable, production from the date acquisitions were completed through the date of the reserve report. Management uses reserve replacement cost to compare our company to others in terms of our historical ability to increase our reserve base in an economic manner. However, our historical reserve replacement costs are not necessarily indicative of the reserve replacement costs we will incur in the future. Historical sources of reserve additions, such as acquisitions, may be more expensive or unavailable in the future. Increases in commodity prices in recent years, and corresponding increases in the market value of oil and natural gas properties, have resulted in increases in our reserve replacement costs. In addition, some companies define reserve replacement cost differently than we do, a fact that limits the usefulness of reserve replacement cost as a comparative measure in some circumstances.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The discussion in 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, sell calls 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 is beneficial. We had hedging contracts (excluding floors) in place for approximately 70% of our oil production and approximately 49% of our natural gas production during the year ended December 31, 2006.

We are subject to interest rate risk with respect to amounts borrowed under our credit facilities because such amounts bear interest at variable rates. As of March 30, 2007, there was approximately $420.9 million outstanding under those facilities. On May 4, 2006, we entered into an interest rate swap transaction to lock in our interest cost on $200.0 million of borrowings at a fixed rate of 9.9225%, including a 4.5% margin, through May 8, 2008. A 1.0% increase in interest rates on unhedged variable rate borrowings of $180.1 million at December 31, 2006 would result in additional annualized interest expense of $1.8 million.

Cumulative Effect of Derivative Transactions

Oil. As of December 31, 2006, we had entered into option (including 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, 2006 for production:				
January 1—December 31, 2007	7,313	$49.72	6,115	$71.58
January 1—December 31, 2008	4,950	$54.43	4,950	$75.38
January 1—December 31, 2009	4,580	$53.94	4,580	$76.78
January 1—December 31, 2010	4,500	$60.00	4,500	$72.96

Natural Gas. As of December 31, 2006, we had entered into option, swap and collar agreements to receive average minimum and maximum PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/d	Weighted Avg. Prices	MMBtu/d	Weighted Avg. Prices
Natural gas derivatives at December 31, 2006 for production:				
January 1—December 31, 2007	21,000	$6.93	15,436	$10.78
January 1—December 31, 2008	13,500	$7.48	11,947	$11.65
January 1—December 31, 2009	9,500	$7.61	9,500	$12.10
January 1—December 31, 2010	10,000	$7.22	10.000	$10.57

Exhibit Number	Exhibit
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).
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).
10.2	Amended and Restated Term Loan Agreement, dated as of April 28, 2006, by and among Venoco, Inc., the Guarantors identified therein, Credit Suisse, Cayman Islands Branch, as Administrative Agent, Credit Suisse Securities (USA) LLC and Lehman Brothers Inc., as Joint Lead Arrangers, Harris Nesbitt Corp., as Co-Arranger, and Lehman Brothers Inc., as Syndication Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 4, 2006).
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	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).

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The discussion in 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, sell calls 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 is beneficial. We had hedging contracts (excluding floors) in place for approximately 70% of our oil production and approximately 49% of our natural gas production during the year ended December 31, 2006.

We are subject to interest rate risk with respect to amounts borrowed under our credit facilities because such amounts bear interest at variable rates. As of March 30, 2007, there was approximately $420.9 million outstanding under those facilities. On May 4, 2006, we entered into an interest rate swap transaction to lock in our interest cost on $200.0 million of borrowings at a fixed rate of 9.9225%, including a 4.5% margin, through May 8, 2008. A 1.0% increase in interest rates on unhedged variable rate borrowings of $180.1 million at December 31, 2006 would result in additional annualized interest expense of $1.8 million.

Cumulative Effect of Derivative Transactions

Oil. As of December 31, 2006, we had entered into option (including 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, 2006 for production:				
January 1—December 31, 2007	7,313	$49.72	6,115	$71.58
January 1—December 31, 2008	4,950	$54.43	4,950	$75.38
January 1—December 31, 2009	4,580	$53.94	4,580	$76.78
January 1—December 31, 2010	4,500	$60.00	4,500	$72.96

Natural Gas. As of December 31, 2006, we had entered into option, swap and collar agreements to receive average minimum and maximum PG&E Citygate prices as follows:

	Minimum		Maximum	
	MMBtu/d	Weighted Avg. Prices	MMBtu/d	Weighted Avg. Prices
Natural gas derivatives at December 31, 2006 for production:				
January 1—December 31, 2007	21,000	$6.93	15,436	$10.78
January 1—December 31, 2008	13,500	$7.48	11,947	$11.65
January 1—December 31, 2009	9,500	$7.61	9,500	$12.10
January 1—December 31, 2010	10,000	$7.22	10.000	$10.57

Portfolio of Derivative Transactions

Our portfolio of commodity derivative transactions as of December 31, 2006 is summarized below:

Oil

Type of Contract	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	NYMEX	2,000	$40.00/$65.80	Jan 1—Dec 31, 07
Collar	NYMEX	1,000	$40.00/$67.50	Jan 1—Dec 31, 07
Collar	NYMEX	1,000	$58.00/$76.25	Jan 1—Dec 31, 07
Collar	NYMEX	1,600	$53.00/$75.00	Jan 1—Jun 30, 07
Collar	NYMEX	1,030	$53.00/$75.00	Jul 1—Dec 31, 07
Put(1)	NYMEX	2,000	$ 58.00 Floor	Jan 1—Dec 31, 07
Call(2)	NYMEX	566	$ 77.15 Cap	Jan 1—Jun 30, 07
Call(3)	NYMEX	1,035	$ 81.00 Cap	Jul 1—Dec 31, 07
Collar	NYMEX	3,450	$52.00/$75.00	Jan 1—Jun 30, 08
Collar	NYMEX	2,450	$52.00/$75.00	Jul 1—Dec 31, 08
Collar	NYMEX	1,000	$58.00/$78.00	Jul 1—Dec 31, 08
Collar	NYMEX	1,500	$58.00/$75.25	Jan 1—Dec 31, 08
Collar	NYMEX	2,170	$50.00/$75.00	Jan 1—Jun 30, 09
Collar	NYMEX	1,000	$56.00/$79.25	Jul 1—Dec 31, 09
Collar	NYMEX	3,000	$55.00/$77.00	Jan 1—Dec 31, 09
Collar	NYMEX	3,500	$60.00/$73.00	Jan 1—Dec 31, 10
Collar	NYMEX	1,000	$60.00/$72.80	Jan 1—Dec 31, 10

(1) Option premium deferred until each month's settlement period ($3,087,900 total deferred).

(2) Option premium deferred until each month's settlement period ($405,409 total deferred).

(3) Option premium deferred until each month's settlement period ($754,206 total deferred).

Natural Gas

Type of Contract	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Collar	Citygate	6,000	$6.00/$8.40	Jan 1—Dec 31, 07
Collar	NYMEX	5,000	$8.00/$14.60	Jan 1—Dec 31, 07
Put(1)	NYMEX	10,000	$7.985 Floor	Jan 1—Dec 31, 07
Call(2)	NYMEX	4,564	$12.15 Cap	Jan 1—Jun 30, 07
Call(3)	NYMEX	4,310	$11.95 Cap	Jul 1—Dec 31, 07
Basis Swap	PG&E Citygate	10,000	$(0.58)	Jan 1—Dec 31, 07
Basis Swap	PG&E Citygate	10,000	$(0.46)	Jan 1—Dec 31, 07
Put(4)	NYMEX	6,000	$8.00 Floor	Jan 1—Dec 31, 08
Call(5)	NYMEX	4,513	$12.15 Cap	Jan 1—Jun 30, 08
Call(6)	NYMEX	4,382	$10.60 Cap	Jul 1—Dec 31, 08
Collar	NYMEX	7,500	$8.00/$12.75	Jan 1—Dec 31, 08
Basis Swap	PG&E Citygate	10,000	$(0.32)	Jan 1—Dec 31, 08
Basis Swap	PG&E Citygate	10,000	$(0.38)	Jan 1—Dec 31, 08
Swap	NYMEX	1,250	$8.72 Fixed	Jan 1—Jun 30, 09
Collar	NYMEX	1,250	$7.75/$13.05	Jan 1—Jun 30, 09
Swap	NYMEX	1,250	$8.00 Fixed	Jul 1—Dec 31, 09
Collar	NYMEX	1,250	$7.25/$11.30	Jul 1—Dec 31, 09
Collar	NYMEX	7,000	$7.50/$12.75	Jan 1—Dec 31, 09
Collar	NYMEX	10,000	$7.00/$10.35	Jan 1—Dec 31, 10
Basis Swap	PG&E Citygate	10,000	$0.22	Jan 1—Dec 31, 10

(1) Option premium deferred until each month's settlement period ($3,650,000 total deferred).
(2) Option premium deferred until each month's settlement period ($776,465 total deferred).
(3) Option premium deferred until each month's settlement period ($745,445 total deferred).
(4) Option premium deferred until each month's settlement period ($2,755,980 total deferred).
(5) Option premium deferred until each month's settlement period ($928,153 total deferred).
(6) Option premium deferred until each month's settlement period ($911,203 total deferred).

In February 2007, we entered into additional derivative contracts for oil and natural gas production from April 2007 through December 2010 as summarized below.

Oil

Type of Contract	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	NYMEX	2,000	$57.00/$73.55	Apr 1—Dec 31, 07
Swap	NYMEX	2,500	$67.25	Jan 1—Dec 31, 08
Swap	NYMEX	2,000	$67.22	Jan 1—Dec 31, 09
Swap	NYMEX	1,000	$66.75	Jan 1—Dec 31, 10

Exhibit Number	Exhibit
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).
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).
10.2	Amended and Restated Term Loan Agreement, dated as of April 28, 2006, by and among Venoco, Inc., the Guarantors identified therein, Credit Suisse, Cayman Islands Branch, as Administrative Agent, Credit Suisse Securities (USA) LLC and Lehman Brothers Inc., as Joint Lead Arrangers, Harris Nesbitt Corp., as Co-Arranger, and Lehman Brothers Inc., as Syndication Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 4, 2006).
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	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).

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 2007 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 2007 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 2007 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 2007 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 2007 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
2.1	Agreement and Plan of Merger, dated as of March 30, 2006, by and among TexCal Energy (LP) LLC, Venoco, Inc., Bicycle Acquisition Company, LLC and Member Rep LLC (incorporated by reference to Exhibit 2.1 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
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	Bylaws of Venoco, Inc. (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
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 (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-4 of Venoco, Inc. filed on March 31, 2005).

Exhibit Number	Exhibit
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).
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).
10.2	Amended and Restated Term Loan Agreement, dated as of April 28, 2006, by and among Venoco, Inc., the Guarantors identified therein, Credit Suisse, Cayman Islands Branch, as Administrative Agent, Credit Suisse Securities (USA) LLC and Lehman Brothers Inc., as Joint Lead Arrangers, Harris Nesbitt Corp., as Co-Arranger, and Lehman Brothers Inc., as Syndication Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 4, 2006).
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	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
10.4.1	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).
10.5	Platform Agreement, dated as of March 1, 2006, by and between Venoco, Inc. and Clearwater Port, LLC (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.6	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).
10.6.1	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).
10.6.2	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).
10.6.3	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).
10.6.4	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).
10.7	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).
10.7.1	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	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).
10.9.1	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).
10.9.2	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).
10.10.1	Employment Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and David Christofferson (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.10.2	Non-Qualified Stock Option Agreement, dated as of May 4, 2005, by and between Venoco, Inc. and David Christofferson (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 16, 2005).
10.10.3	Separation Agreement, dated as of January 29, 2007, by and between Venoco, Inc. and David Christofferson.

Exhibit Number	Exhibit
10.11.1	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).
10.11.2	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).
10.12.1	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).
10.12.2	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).
10.13	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).
10.14	Employment Agreement, dated as of March 19, 2007, by and between Venoco, Inc. and Timothy A. Ficker.
10.15	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).
10.16	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	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).
10.18	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).
10.19.1	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).
10.19.2	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).
10.19.3	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	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).
21.1	Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).

Exhibit Number	Exhibit
23.1	Consent of Deloitte & Touche LLP.
23.2	Consent of Netherland, Sewell & Associates, Inc.
23.3	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 Executive 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: April 2, 2007

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)	April 2, 2007
/s/ DAVID B. CHRISTOFFERSON David B. Christofferson	Chief Financial Officer (Principal Financial Officer)	April 2, 2007
/s/ DOUGLAS J. GRIGGS Douglas J. Griggs	Chief Accounting Officer (Principal Accounting Officer)	April 2, 2007
/s/ J. TIMOTHY BRITTAN J. Timothy Brittan	Director	April 2, 2007
/s/ J.C. MCFARLAND J.C. McFarland	Director	April 2, 2007
Eloy U. Ortega	Director	April 2, 2007
/s/ JOEL L. REED Joel L. Reed	Director	April 2, 2007
Mark A. Snell	Director	April 2, 2007
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	Director	April 2, 2007

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

**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 sheets of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, comprehensive income, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
April 2, 2007

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except shares amounts)

	December 31, 2005 (Successor)	December 31, 2006 (Successor)
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 9,389	$ 8,364
Accounts receivable, net of allowance for doubtful accounts of $759 and $1,250 at December 31, 2005 and 2006, respectively	29,841	48,042
Inventories	1,753	3,211
Prepaid expenses and other current assets	4,351	7,226
Income tax receivable	4,107	8,098
Deferred income taxes	8,611	879
Commodity derivatives	3,391	10,348
Total current assets	61,443	86,168
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Oil and natural gas properties (full cost method, of which $2,275 and $4,850 for unproved properties were excluded from amortization at December 31, 2005 and 2006, respectively)	269,922	881,570
Drilling equipment	7,947	13,731
Other property and equipment	27,424	12,380
Total property, plant and equipment	305,293	907,681
Accumulated depletion, depreciation and amortization	(71,517)	(133,428)
Net property, plant and equipment	233,776	774,253
OTHER ASSETS:		
Commodity derivatives	69	8,591
Deferred loan costs	5,658	17,318
Other	1,612	6,863
Total other assets	7,339	32,772
TOTAL ASSETS	$302,558	$ 893,193
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 31,134	$ 53,900
Undistributed revenue payable	2,155	15,596
Interest payable	720	5,295
Current maturities of long-term debt	126	3,557
Commodity derivatives	26,397	8,574
Total current liabilities	60,532	86,922
LONG-TERM DEBT	178,943	529,616
DEFERRED INCOME TAXES	24,108	40,424
COMMODITY DERIVATIVES	11,992	6,931
ASSET RETIREMENT OBLIGATIONS	22,649	38,984
Total liabilities	298,224	702,877
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value (200,000,000 shares authorized; 32,692,500 and 42,783,300 shares issued and outstanding at December 31, 2005 and 2006, respectively)	327	428
Additional paid-in capital	20,976	181,444
Retained earnings (accumulated deficit)	(3,785)	10,910
Accumulated other comprehensive loss	(13,184)	(2,466)
Total stockholders' equity	4,334	190,316
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$302,558	$ 893,193

See notes to consolidated financial statements.

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

	Years Ended December 31,		
	2004 (Predecessor)	2005 (Successor)	2006 (Successor)
REVENUES:			
Oil and natural gas sales	$139,961	$191,092	$274,813
Commodity derivative (losses)	(18,685)	(57,595)	(2,365)
Other	5,457	4,456	5,470
Total revenues	126,733	137,953	277,918
EXPENSES:			
Oil and natural gas production	49,567	54,038	87,505
Transportation expense	2,915	2,596	3,533
Depletion, depreciation and amortization	16,489	21,680	63,259
Accretion of abandonment liability	1,482	1,752	2,542
General and administrative, net of amounts capitalized	11,272	16,007	28,317
Amortization of deferred loan costs	3,050	1,755	3,776
Interest, net	2,269	13,673	49,385
Total expenses	87,044	111,501	238,317
Income before income taxes and minority interest	39,689	26,452	39,601
INCOME TAXES:			
Current	5,479	13,000	610
Deferred	10,609	(2,700)	15,040
Total income taxes	16,088	10,300	15,650
Net income before minority interest	23,601	16,152	23,951
Minority interest in Marquez Energy	95	42	—
Net income	23,506	16,110	23,951
Preferred stock dividends	(7,134)	—	—
Excess of carrying value over repurchase price of preferred stock	29,904	—	—
Net income applicable to common equity	$ 46,276	$ 16,110	$ 23,951
Earnings per common share:			
Basic	$ 1.33	$ 0.49	$ 0.71
Diluted	$ 0.48	$ 0.49	$ 0.69

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands)

	Years Ended December 31,		
	2004	2005	2006
	(Predecessor)	(Successor)	(Successor)
Net income	$23,506	$ 16,110	$23,951
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Hedging activities:			
Reclassification adjustments for settled contracts(1)	1,293	(410)	3,602
Changes in fair value of outstanding hedging positions(2)	1,943	(14,697)	7,116
Other comprehensive income (loss)	3,236	(15,107)	10,718
Comprehensive income	$26,742	$ 1,003	$34,669

(1) Net of tax (benefit) of $849, $(270) and $2,389 for the years ended December 31, 2004, 2005 and 2006, respectively.

(2) Net of tax (benefit) of $1,276, $(9,686) and $4,720 for the years ended December 31, 2004, 2005 and 2006, respectively.

See notes to consolidated financial statements.

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount	Shares	Amount				
BALANCE AT AT JANUARY 1, 2004 (Predecessor)	35,890	$359	984	$(1,500)	$ (12)	$ 4,950	$(1,313)	$ 2,484
Comprehensive income:								
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	—	—	1,293	1,293
Change in value of derivatives, net of tax	—	—	—	—	—	—	1,943	1,943
Net income	—	—	—	—	—	23,506	—	23,506
Excess of carrying value over repurchase price of preferred stock	—	—	—	—	29,904	—	—	29,904
Marquez Energy equity, net of minority interest	—	—	—	—	1,736	1,356	—	3,092
Preferred stock dividends	—	—	—	—	—	(7,134)	—	(7,134)
Purchase accounting adjustments	(3,197)	(32)	(984)	1,500	(543)	(7,574)	—	(6,649)
BALANCE AT DECEMBER 31, 2004 (Successor)	32,693	327	—	—	31,085	15,104	1,923	48,439
Comprehensive income:								
Reclassification adjustment for settled contracts, net of tax	—	—	—	—	—	—	(410)	(410)
Change in value of derivatives, net of tax	—	—	—	—	—	—	(14,697)	(14,697)
Distribution payments to Marquez Energy member, net of minority interest	—	—	—	—	(645)	—	—	(645)
Payment of dividends to shareholder	—	—	—	—	—	(35,000)	—	(35,000)
Marquez Energy acquisition adjustment	—	—	—	—	(9,464)	1	—	(9,463)
Net income	—	—	—	—	—	16,110	—	16,110
BALANCE AT DECEMBER 31, 2005 (Successor)	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	—	—	—	—	—	23,951	—	23,951
BALANCE AT DECEMBER 31, 2006 (Successor)	42,783	$428	—	$ —	$181,444	$ 10,910	$(2,466)	$190,316

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2004	2005	2006
	(Predecessor)	(Successor)	(Successor)
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 23,506	$ 16,110	$ 23,951
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	16,489	21,680	63,259
Accretion of abandonment liability	1,482	1,752	2,542
Deferred income taxes (benefit)	10,609	(2,700)	15,040
Share-based compensation	—	—	3,050
Amortization of deferred loan costs	3,050	1,755	3,776
Amortization of bond discounts and other non-cash interest	—	137	1,124
Minority interest in undistributed earnings	95	42	—
Unrealized commodity derivative (gains) losses and amortization of premiums	1,096	36,937	(12,898)
Other	(102)	—	(177)
Changes in operating assets and liabilities, net of working capital acquired:			
Accounts receivable	(976)	(12,739)	3,534
Inventories	(118)	(674)	(1,458)
Prepaid expenses and other current assets	(241)	(873)	(955)
Income tax receivable	(2,721)	(201)	(2,092)
Other assets	(3)	(559)	272
Accounts payable and accrued liabilities	(2,592)	410	(4,301)
Undistributed revenue payable	1,445	(2,619)	1,865
Other liabilities	(1,198)	(92)	—
Net premiums paid on derivative contracts	(6,512)	(18,435)	(7,442)
Net cash provided by operating activities	43,309	39,931	89,090
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for oil and natural gas properties	(16,181)	(77,657)	(165,748)
Acquisitions of oil and natural gas properties	(165)	(10,636)	(19,461)
Expenditures for drilling equipment	(22)	(353)	(5,666)
Expenditures for other property and equipment	(239)	(1,460)	(3,199)
Purchase of new building	(14,653)	—	—
Proceeds from sale of oil and natural gas properties	1,526	44,619	46,389
Proceeds from sale of other property and equipment	228	—	—
Acquisition of TexCal Energy, net of cash acquired	—	—	(447,519)
Acquisition of Marquez Energy, LLC	(672)	(14,628)	—
Notes receivable—officers	2,188	1,420	—
Net cash used in investing activities	(27,990)	(58,695)	(595,204)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	272,397	59,000	569,529
Principal payments on long-term debt	(159,654)	(43,737)	(210,101)
Increase in deferred loan costs	(9,653)	(817)	(15,335)
Proceeds from derivative premium financing	—	—	3,903
Purchase of preferred stock and unpaid dividends	(72,000)	—	—
Proceeds from issuance of common stock	—	—	160,393
Stock issuance costs	—	—	(2,874)
Dividend paid to shareholder	—	(35,000)	(426)
Contributions from Marquez Energy members	500	—	—
Distribution payments to Marquez Energy members	(611)	(707)	—
Repurchase of common shares	—	(5,301)	—
Net cash (used in) provided by financing activities	30,979	(26,562)	505,089
Net (decrease) increase in cash and cash equivalents	46,298	(45,326)	(1,025)
Cash and cash equivalents, beginning of period	8,417	54,715	9,389
Cash and cash equivalents, end of period	$ 54,715	$ 9,389	$ 8,364
Supplemental Disclosure of Cash Flow Information—			
Cash paid during the year for:			
Interest	$ 2,524	$ 14,223	$ 44,540
Income taxes	$ 8,200	$ 13,400	$ 2,701
Supplemental Disclosure of Noncash Activities—			
Decrease (increase) in accrued capital expenditures	$ 5,222	$ 11,899	$ (19,420)
Distributions of land and building	$ —	$ —	$ 18,399
Distribution of building note payable	$ —	$ —	$ 9,857

See notes to consolidated financial statements.

1. ORGANIZATION AND NATURE OF OPERATIONS

General—Venoco, Inc. (the "Company"), a Delaware corporation, is engaged in the business of acquiring interests in, and exploring for and developing, oil and natural gas properties with a focus offshore and onshore California.

New Company Basis—During 2004, the Company's CEO, Tim Marquez, increased his ownership in the Company from 41% to 100%. In a transaction that closed on July 12, 2004, Mr. Marquez paid an aggregate of $16.2 million in cash for 18,509,468 shares of common stock of the Company (representing 53% of the common stock then outstanding) from two of the Company's former officers and their respective affiliates. On December 22, 2004, the Company merged with a corporation the sole stockholder of which was a trust controlled by Mr. Marquez. In the merger, the Company paid an aggregate of $5.4 million in cash for 2,212,208 shares of common stock. The merger resulted in an increase in Mr. Marquez's beneficial ownership of the Company's common stock from 94% to 100%.

As a result of Mr. Marquez obtaining control of over 95% of the common stock of the Company on December 22, 2004, SEC Staff Accounting Bulletin No. 54 requires the acquisition by Mr. Marquez to be "pushed-down," meaning the post-transaction financial statements of the acquired entity reflect a new basis of accounting. Due to the *de minimis* impact on the Company's results of operations for the nine-day period ended December 31, 2004, the new company basis of accounting has been applied to the Company's financial statements as of December 31, 2004.

The purchase price paid as a result of each transaction described above has been allocated to the underlying assets and liabilities based upon Mr. Marquez's acquired interests (53% on July 12, 2004 and 6% on December 22, 2004) in the respective fair market values of assets and liabilities at the date of each transaction. Accordingly, adjustments have been made to the historical values of assets and liabilities which reflect Mr. Marquez's acquisition of the common stock of the Company that he did not already own. Fair value was determined using a variety of valuation methods, including third party appraisals.

The following represents the estimated values attributable to the assets acquired and liabilities assumed in Mr. Marquez's acquisition of the remaining 59% ownership in the Company. These values include the historical values attributable to Mr. Marquez's predecessor basis (in thousands).

Consideration paid for 18,509,468 common shares (53% of the total outstanding) on July 12, 2004	$ 16,185
Consideration paid to minority shareholders as a result of statutory merger for 2,212,208 common shares (6% of the total outstanding) on December 22, 2004	5,439
Total purchase price	$ 21,624
Allocation of purchase price:	
Current assets	$ 83,791
Oil and natural gas properties	161,892
Other property, plant and equipment	19,049
Land	10,303
Other non-current assets	12,468
	287,503
Current liabilities	29,689
Long-term debt	158,858
Deferred incomes taxes	32,208
Asset retirement obligations	22,408
	243,163
Net assets	44,340
Historical net assets attributable to non-selling interests (Predecessor basis for Mr. Marquez's 41% ownership of the Company as of June 30, 2004)	(22,716)
Fair value of net assets acquired	$ 21,624

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation—The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. All significant 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) income taxes; (7) accrued liabilities; (8) valuation of derivative instruments; and (9) accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Business Segment Information—The Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 131, Disclosures about Segments of an Enterprise and Related Information, establishes standards for reporting information about operating segments. Operating segments are defined as components of an enterprise that engage in activities from which the Company may earn revenues and incur expenses.

The Company operates in one segment as each of its operating areas have similar economic characteristics and each meets the criteria for aggregation as defined in SFAS No. 131. All of the Company's operations involve the exploration, development and production of oil and natural gas and currently all operations are located in the United States. The Company has a single, company-wide management team that administers all properties as a whole rather than as discrete operating segments. The Company tracks only basic operational data by area and does not maintain separate financial statement information by area. The chief decision maker measures financial performance as a single enterprise and not on an area-by-area basis. Throughout the year, the chief decision maker freely allocates capital resources on a project-by-project basis across the Company's entire asset base to maximize profitability without regard to individual areas or segments.

Concentration of Credit Risk—The Company's accounts receivable result from oil and natural gas sales to major oil and intrastate gas pipeline companies and to joint venture partners that own interests in properties operated by the Company. The Company's trade and accrued production receivables are dispersed among various customers and purchasers; therefore, concentrations of credit risk are limited. Also, most of the Company's significant purchasers are large companies with excellent credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support lines of credit. For the year ended December 31, 2004, the Company's oil and natural gas sales to three major customers represented 48%, 27% and 11% of its total revenues. For the year ended December 31, 2005, the Company's oil and natural gas sales to three major customers represented 48%, 20% and 15% of its total revenues. For the year ended December 31, 2006, the Company's oil and natural gas sales to four major customers represented 31%, 20%, 13% and 12% of its total revenues. The Company recorded an allowance for doubtful accounts as of December 31, 2005 and 2006 of $0.8 million and $1.3 million, respectively, for customer accounts. As of December 31, 2006, 16%, 14%, 8% and 0% of the total accounts receivable balance was receivable from the Company's four major customers.

Revenue Recognition and Gas Imbalances—The Company records revenues from sales of natural gas and crude oil when title to the customer has transferred as defined in related sales contracts. 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 oil produced. 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. Production imbalances are valued at the lowest of (1) the price in effect at the time of production, (2) the current market value, or (3) if a contract is in-hand, the contract price. The Company's production imbalances were not material at December 31, 2005 and 2006.

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

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, or FIFO). 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 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, 2004, 2005, and 2006 was $14.8 million, $20.5 million, and $61.0 million, respectively ($3.63, $4.85, and $10.52, 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 established or impairment 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. Impairment losses of $0.1 million related to foreign properties were recorded for the year ended December 31, 2004. No impairment losses were incurred in 2005 or 2006. Interest costs capitalized as part of unproved property costs were $0.4 million for the year ended December 31, 2004. No interest costs were capitalized in 2005 or 2006 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. The Company uses derivative financial instruments that qualify for cash flow hedge accounting under SFAS No. 133 to hedge against the volatility of crude oil and natural gas prices, and in accordance with Securities and Exchange Commission guidelines, the Company includes estimated future cash flows from its hedging program in the ceiling test calculation. At December 31, 2005 and 2006, the Company's net capitalized costs did not exceed the ceiling.

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 $2.3 million, $2.5 million, and $4.4 million directly related to its acquisition, exploration and development activities during 2004, 2005 and 2006, 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, 2004, 2005 and 2006 was $1.6 million, $1.2 million and $2.3 million, respectively.

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, all derivative instruments are recorded on the balance sheet at fair value. 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 oil and natural gas revenues. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, the Company has designated certain derivatives as cash flow hedges for accounting purposes and the remaining discussion will relate exclusively to this type of derivative instrument. 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 total oil and natural gas revenues in the period the hedged production occurs.

In order to qualify for hedge accounting, the relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. The Company measures effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedge instrument is no longer considered highly effective. Gains and losses deferred in OCI related to cash flow hedges that are determined to be no longer highly effective remain unchanged until the related product is delivered. If it is determined that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

The Company determines hedge ineffectiveness based on changes during the period in the price differentials between the index price of the derivative contracts (which uses a New York Mercantile Exchange ("NYMEX") index in the case of oil hedges, and NYMEX and PG&E Citygate in the case of natural gas hedges) and the contract price for the point of sale for the cash flow that is being hedged. Hedge ineffectiveness occurs only if the cumulative gain or loss on the derivative hedging instrument exceeds the cumulative change in the expected future cash flows on the hedged transaction. Ineffectiveness is recorded in earnings to the extent the cumulative changes in fair value of the actual derivative exceed the cumulative changes in fair value of the hypothetical derivative.

Fair Value of Financial Instruments—The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, derivatives 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 of December 31, 2006, the carrying value of long-term debt approximates its fair value because the stated rate of interest approximates the market rate. The Company's derivative financial instruments are reported on the balance sheet at fair value.

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.

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 net income per common share of stock is calculated by dividing net income available to common stockholders by the weighted average number of common shares outstanding during each period.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted average of common shares outstanding, including the effect of other dilutive securities. Adjusted net income is calculated using the if-converted method and, for periods during 2004 when shares of the Company's mandatorily redeemable convertible non-participating preferred stock were outstanding, is derived by adding dividends paid or accrued on such preferred stock back to net income and then adjusting for nondiscretionary items that (i) are based on income and (ii) would have changed had the preferred shares been converted at the beginning of the period. Potentially dilutive securities of the Company consist of outstanding in-the-money options to purchase the Company's common stock and shares into which the preferred stock may be converted. No preferred stock was outstanding as of December 31, 2005 and 2006.

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:

	Years ended December 31,		
	2004	2005	2006
	(Predecessor)	(Successor)	(Successor)
Dilutive	—	2,272,239	3,952,569
Anti-dilutive	335,764	816,553	318,169

Shares associated with the conversion feature of the preferred stock outstanding in 2004 were accounted for using the if-converted method as described above. A total of 14,528,638 potentially dilutive shares related to the preferred stock were included in the calculation of diluted net income per common share for the year ended December 31, 2004. In November 2004, the Company repurchased all of the outstanding preferred stock.

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

	Year ended December 31,		
	2004 (Predecessor)	2005 (Successor)	2006 (Successor)
Net income attributable to common shareholders	$ 46,276	$16,110	$23,951
Adjustments to net income for dilution:			
Add: Preferred stock dividend if convertible preferred stock converted to equity	7,134	—	—
Deduct: Excess of carrying value over repurchase price of preferred stock	(29,904)	—	—
Net income adjusted for the effect of dilution	$ 23,506	$16,110	$23,951
Basic weighted average common shares outstanding	34,858	32,693	33,795
Add: dilutive effect of stock options	—	286	1,065
Add: dilutive effect of convertible preferred stock	14,529	—	—
Diluted weighted average common shares outstanding	49,387	32,979	34,860
Basic earnings per common share	$ 1.33	$ 0.49	$ 0.71
Diluted earnings per common share	$ 0.48	$ 0.49	$ 0.69

Stock-Based Compensation—Prior to January 1, 2006, the Company accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees if the grant price equaled or exceeded the market price on the date of the option grant. Effective January 1, 2006, the Company adopted the provisions of 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 also requires the recognition of the equity component of deferred compensation as additional paid-in capital.

In accordance with the provisions of SFAS 123R, the Company recognized total stock-based compensation cost in the amount of $3.1 million for the year ended December 31, 2006 including $2.8 million as general and administrative expense and $0.3 million as oil and natural gas production expense. SFAS 123R 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. The cumulative adjustment from adopting SFAS 123R as of January 1, 2006 to include estimated forfeitures in the calculation was not material and had no impact on earnings per share.

No compensation cost was recorded prior to January 1, 2006 as all stock options had an exercise price equal to or greater than the market value of the underlying common stock on the date of grant. The following table illustrates the pro forma effect on net income and earnings per common share if the Company had recognized compensation expense for all options granted based upon the estimated fair value on the grant date under the fair value methodology prescribed by SFAS No. 123, "*Accounting for Stock-Based Compensation*" (in thousands except per share amounts):

	Year ended December 31,	
	2004	2005
	(Predecessor)	(Successor)
Net income as reported	$46,276	$16,110
Less: Total stock based compensation expense determined under the fair value method for all awards, net of related tax effects	(62)	(2,300)
Pro forma net income	$46,214	$13,810
Basic income per share:		
As reported	$ 1.33	$ 0.49
Pro forma	$ 1.33	$ 0.42
Diluted income per share:		
As reported	$ 0.48	$ 0.49
Pro forma	$ 0.47	$ 0.42

For purposes of the pro forma disclosures, the estimated fair values of the options are amortized to expense over the options' vesting periods.

Reclassifications—The consolidated statements of operations were modified to combine commodity derivative gains and losses into one caption. The components of the caption are disclosed in the footnotes to the financial statements. This reclassification had no impact on total revenues. The statement of cash flows was modified to segregate acquisitions of oil and natural gas properties from capital expenditures for oil and natural gas properties. This reclassification had no impact on cash flows from operating, investing or financing activities.

New Accounting Standards

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on the related derecognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. The interpretation is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the effect that the adoption of FIN 48 will have on its consolidated financial statements and has not yet determined whether or not the adoption will have a material impact on its consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of SFAS 157 is not expected to have a material impact on the Company's consolidated financial position or results of operations. However, additional disclosures may be required about the information used to develop the measurements.

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"). SAB 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. The SEC staff believes that registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 is effective for the first annual period ending after November 15, 2006 and provides for a one-time transitional cumulative effect adjustment to beginning retained earnings as of January 1, 2006 for errors that were not previously deemed material but are deemed material under the guidance in SAB 108. The adoption of SAB 108 did not have a material impact on the Company's consolidated financial position or results of operations.

3. ACQUISITIONS AND SALES OF PROPERTIES

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 production company with properties in Texas and California, for approximately $456.8 million in cash and related financing costs of $14.4 million. TexCal had proved reserves of 31.4 MMBOE as of December 31, 2005 according to a reserve report prepared by TexCal's independent engineers. 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 new 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 preliminarily 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, 2005 and 2006 give effect to the TexCal Acquisition as if it had been completed as of January 1, 2005 and January 1, 2006. The pro forma amounts shown below are not necessarily indicative of the operating results that would have occurred if the transaction 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).

	Year Ended, December 31,	
	2005	2006
	(Successor)	(Successor)
Total Revenues	$221,123	$306,669
Net Income	$ 29,059	$ 35,126
Basic earnings per common share	$ 0.89	$ 1.07
Dilutive earnings per share	$ 0.88	$ 1.01

Union Island. In December 2005, the Company purchased the Union Island pipeline, a 32-mile natural gas pipeline running from the Union Island field to a location near Pittsburg, California, for $6.1 million.

Willows-Beehive. In September 2005, the Company acquired a 100% working interest in the Willows-Beehive Bend Gas Field, a 100% working interest in the Bounde Creek Gas Field and a 65% working interest in the Arbuckle Field for an aggregate net price of $10.1 million in cash. The Company operates all of the fields, which are located in the Sacramento Basin in California.

In January 2006, the Company sold 35% of the interests it acquired in the Willows-Beehive Bend and Bounde Creek gas fields for $3.0 million. No gain was recognized from the sale for financial reporting purposes. The Company applied the proceeds of the sale to reduce the capitalized cost of oil and natural gas properties.

In December 2006, the Company closed a transaction pursuant to which it sold a portion of its interests in the Arbuckle, Bounde Creek and Beehive Bend fields and purchased additional interests in the Willows and Grimes fields and the Grizzly Island area of mutual interest. The Company paid net cash consideration of $10.4 million in the transaction and also offset accounts receivable from the third party of $3.1 million as additional consideration for the interests acquired.

CO_2 Project with Denbury. In November 2006, the Company entered into an option agreement with Denbury Resources relating to a potential CO_2 enhanced recovery project in the Hastings complex. Pursuant to the agreement, Denbury will pay the Company a total of $50.0 million for an option to acquire the Company's interest in parts of the complex and certain related property for use in an enhanced recovery project in which the Company will have a continuing interest. Of the total option payment, $37.5 million was paid in December 2006, $7.5 million will be paid in November 2007 and the remaining $5.0 million will be paid in November 2008. No part of the option payment is refundable. Denbury may not exercise the option prior to September 2008 and the initial exercise period will end in October 2009, subject to Denbury's right to extend it for successive one-year periods until 2016 for an annual extension fee of $30.0 million. Following the exercise of the option, Denbury will either purchase the properties subject to the option or enter into a volumetric production payment arrangement with the Company with respect to the properties. The purchase price or volumetric production payment will be based on the value of the properties as determined with respect to the net proved reserves associated with the properties based on then-existing operations and NYMEX forward strip pricing, subject to certain adjustments. The $50.0 million option payment will not be deducted from the purchase price or payment. In accordance with its accounting policies, the Company did not recognize a gain on sale for financial reporting purposes, but applied the $50.0 million in option payments to reduce the capitalized cost of its oil and natural gas properties and recorded current receivables of $7.5 million for the option payment to be received in November 2007 and non-current receivables of $5.0 for the option payment to be received in November 2008. The Company will continue to operate the properties in the normal course of business.

Marquez Energy Acquisition. On March 21, 2005, the Company acquired Marquez Energy, a Colorado limited liability company that was majority-owned and controlled by Tim Marquez. Because of the common ownership of Marquez Energy and the Company, this acquisition has been recorded in a manner similar to a pooling-of-interests. Common control occurred in July 2004 when Tim Marquez acquired an additional 53% of the Company's common stock bringing his common stock holdings to 94%. The Company's financial statements have been adjusted to give effect to the acquisition of Marquez Energy as if it had occurred in July 2004. In addition, because of the common control, Tim Marquez's historical basis in Marquez Energy has been carried over and the excess purchase price of $9.4 million, net of deferred taxes, has been charged directly to equity. Oil and natural gas properties were written up to their pro rata fair values for amounts paid to minority interests. Due to the *de minimis* impact on Marquez Energy's results of operations for the ten-day period following the closing, the acquisition was recorded as if it had occurred on March 31, 2005.

The following table summarizes the recording of the Marquez Energy acquisition (in thousands).

Write up of oil and natural gas properties to fair value—amount paid to minority interests	$ 3,652
Deferred income tax asset	3,658
Charge to equity for excess of purchase price over Mr. Marquez's historical basis, net of deferred taxes	9,831
Credit to equity for elimination of minority interest	(367)
Total purchase price	$16,774

The Company's 2004 statement of operations has been adjusted to add Marquez Energy operations from July 2004 forward. Operations of Marquez Energy alone for the six months ended December 31, 2004 consisted of the following (in thousands):

Natural gas sales	$2,501
Other revenues	322
Total revenues	2,823
Operating expenses	787
D, D&A	148
G&A and other	786
Minority interest	95
Total expenses	1,816
Net income	$1,007

The Marquez Energy acquisition added proved reserves of approximately 2.0 MMBOE (unaudited) as of December 31, 2004 based on a reserve report prepared by Netherland, Sewell and Associates, Inc. (NSAI). The $16.8 million purchase price for Marquez Energy was based on members' equity per Marquez Energy's unaudited December 31, 2004 balance sheet as adjusted to reflect the value of its oil and natural gas properties (as determined by NSAI as of December 31, 2004) and certain other adjustments. For the purpose of calculating the purchase price, the following values were assigned to Marquez Energy's proved reserves (unaudited): (i) $1.75/Mcfe for its proved developed producing reserves, (ii) $1.00/Mcfe for its proved developed non-producing reserves and (iii) $0.75/Mcfe for its proved undeveloped reserves. Pursuant to the purchase agreement, NSAI conducted a supplemental evaluation of the Marquez Energy properties as of December 31, 2005 and 2006 for the purpose of determining whether additional payments were due to the former members of Marquez Energy. No additional payments were due and all contingent payment obligations of the Company pursuant to the purchase agreement have expired.

Big Mineral Creek. In February 2005, the Company entered into a purchase and sale agreement to sell its interest in the Big Mineral Creek field ("BMC"), located in Grayson County, Texas, for $44.6 million. In order to facilitate a like-kind exchange of the Company's BMC property under Section 1031 of the Internal Revenue Code, the proceeds from the sale of $44.6 million were deposited with a qualified intermediary. The Company acquired qualified replacement properties of approximately $15.6 million (including a portion of the Marquez Energy properties) prior to the expiration of the 180 day deadline on September 27, 2005. The Company deferred a portion of the gain on sale of the BMC property under the provisions of section 1031 and recognized a gain for tax purposes on the sale of the BMC property of approximately $27.9 million since the qualified replacement property acquired was less than the proceeds from the sale of the BMC property. In accordance with its accounting policies, the Company did not recognize a gain on sale for financial reporting purposes, but applied the proceeds to reduce the capitalized cost of its oil and natural gas properties.

4. LONG-TERM DEBT

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

	December 31,	
	2005	2006
	(Successor)	(Successor)
Revolving credit agreement due March 2009	$ 20,000	$ 30,579
Second lien term loan due March 2011	—	348,882
8.75% senior notes due December 2011	149,180	149,317
Financed derivative premiums due 2008	—	4,395
5.79% mortgage on office building due January 2015	9,889	—
Total long-term debt	179,069	533,173
Less: current portion of long-term debt	(126)	(3,557)
Long-term debt, net of current portion	$178,943	$529,616

Senior notes. On December 20, 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 beginning June 15, 2005. 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, create liens or sell assets. The senior notes were issued as unsecured obligations, but became secured equally and ratably with the second lien term loan on March 30, 2006.

Proceeds from the sale of the senior notes were used to repay $98.7 million the Company had borrowed against its $102 million Senior Secured Facility (the "Senior Facility") obtained in November 2004. Initial proceeds of $100.7 million from borrowings under the Senior Facility in 2004 were used to purchase all of the Company's mandatorily redeemable convertible preferred stock plus accrued dividends at a cost of $72 million and to repay outstanding borrowings of $27.3 million under the Company's former $150.0 million senior secured revolving/term credit facility entered into in November 2000. In December 2004, the amended and restated Senior Facility became a revolving credit agreement with no associated term loan facility ("revolving credit agreement"). At December 31, 2005, the revolving credit agreement had a borrowing base of $80 million, was secured by a first priority lien on substantially all of the Company's oil and natural gas properties and other assets, including the stock of all of the Company's subsidiaries, and was unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. and 6267 Carpinteria Avenue, LLC. The collateral also secured the Company's obligations to hedging counterparties that were also lenders, or affiliates of lenders, under the revolving credit agreement. As of December 31, 2006, the Company had available borrowing capacity of $198.7 million (net of $0.7 million in outstanding letters of credit). The revolving credit agreement, which was due to mature on November 4, 2007, was amended and restated in connection with the TexCal Acquisition.

TexCal Acquisition Financing. The Company financed the TexCal Acquisition through loans advanced under a second amendment and restatement of the revolving credit agreement and a new senior secured second lien term loan facility. On March 30, 2006, the Company borrowed $350 million pursuant to the second lien term loan facility. On March 31, 2006, the Company borrowed approximately $119.5 million under the amended revolving credit agreement to finance the remainder of the TexCal purchase price and related financing costs of approximately $14.4 million. The term loan facility was amended and restated as of April 28, 2006 and the revolving credit agreement was further amended on May 2, 2006, October 25, 2006 and November 29, 2006. The following summarizes certain terms of the credit facilities as amended as of December 31, 2006.

The amended revolving credit facility has an aggregate maximum loan amount of $300 million and a borrowing base of $230 million. Principal on the second lien term loan facility is payable on March 30, 2011, and principal on the revolving credit facility is payable on March 30, 2009. Pursuant to mandatory prepayment provisions set forth in the credit facilities, substantially all of the proceeds of asset sales and certain additional borrowings, and up to 50% of the proceeds of equity issuances, must be used to reduce amounts outstanding under the revolving credit facilty or offered as prepayments to lenders under the second lien term loan facility. The Company may from time to time make optional prepayments on outstanding loans, subject to the satisfaction of certain conditions. Under the second lien term loan facility, optional prepayments made prior to March 30, 2008 are subject to a prepayment premium. Amounts prepaid under the second lien term loan facility may not be reborrowed. The revolving credit facility is secured by a first priority lien on substantially all of the Company's assets and is guaranteed by each of its subsidiaries other than Ellwood Pipeline, Inc. The second lien term loan facility is secured by second priority liens on the same collateral as the revolving credit agreement. A collateral trust agreement has been entered into in order to provide, for the benefit of the holders of the senior notes, liens on the Company's property that are equal and ratable with the liens securing the second lien term loan facility.

Loans made under the revolving credit agreement and the second lien term loan facility are designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Base Rate Loans under the revolving credit agreement 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) a margin ranging from 0.75% to 1.50%, based upon utilization. LIBO Rate Loans under the revolving credit agreement bear interest at (i) LIBOR plus (ii) a margin ranging from 2.25% to 3.00%, 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.

Base Rate Loans under the second lien term loan facility bear interest at a floating rate equal to (i) the greater of the administrative agent's announced base rate and the overnight federal funds rate plus 0.50% plus (ii) 3.50%. LIBO Rate Loans under the second lien term loan facility bear interest at LIBOR plus 4.50%.

The revolving credit agreement and the second lien term loan facility contain customary representations, warranties, events of default, indemnities and covenants, including financial covenants that require the Company to maintain specified ratios of EBITDA to interest expense, current assets to current liabilities, debt to EBITDA and PV-10 to total debt, and limitations on dividends. As of December 31, 2006, the revolving credit agreement also imposes certain restrictions on acquisitions of oil and natural gas assets and capital expenditures. An October 2006 amendment to the revolving credit agreement also required the Company to enter into derivative contracts covering 75% of its anticipated production from proved developed producing reserves in 2010 at specified prices. The Company was in compliance with all debt covenants at December 31, 2006.

Subsequent to December 31, 2006, the Company entered into an additional amendment to its revolving credit facility. The amendment, entered into on March 1, 2007, eliminated certain restrictions on acquisitions of oil and natural gas assets and capital expenditures.

Financed Derivative Premiums. The Company entered into derivative contracts for options 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. The premiums for the derivative contract options contain an implicit interest rate factor of 16.9% for the difference in the derivative's fair value at inception and the liability for payment of premiums. The financed derivative premiums payable of $4.4 million at December 31, 2006 is net of an unamortized discount of $0.6 million.

Mortgage. On December 9, 2004, 6267 Carpinteria Avenue, LLC ("6267 Carpinteria"), a wholly-owned subsidiary of the Company, purchased an office building in Carpinteria, California for $14.2 million. The purchase was financed in part by a secured 5.79% $10 million promissory note due January 1, 2015. On March 22, 2006, the Company paid a dividend consisting of 100% of the membership interests in 6267 Carpinteria to its sole stockholder, a trust controlled by the Company's CEO. The obligation for the 5.79% mortgage on the office building owned by 6267 Carpinteria was transferred to the sole stockholder in connection with the dividend.

Scheduled annual maturities of long-term debt were as follows at December 31, 2006:

Year Ending December 31 (in thousands):	
2007	$ 3,557
2008	838
2009	30,579
2010	—
2011	498,199
2012 and after	—
	$533,173

5. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

The Company utilizes swap, 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.

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

	Year ended December 31,		
	2004	2005	2006
	(Predecessor)	(Successor)	(Successor)
Realized commodity derivative losses	$(17,589)	$(20,658)	$(15,263)
Amortization of commodity derivative premiums	—	(4,701)	(8,181)
Unrealized commodity derivative gains (losses):			
Change in fair value of derivatives that do not qualify for hedge accounting	1,539	(33,511)	25,040
Ineffective portion of derivatives qualifying for hedge accounting	(2,635)	1,275	(3,961)
Total unrealized commodity derivative gains (losses)	(1,096)	(32,236)	21,079
Total realized and unrealized commodity derivative gains (losses)	$(18,685)	$(57,595)	$ (2,365)

The estimated fair values of derivatives included in the consolidated balance sheets at December 31, 2005 and 2006 are summarized below. The net fair value of the Company's derivatives increased by $38.3 million from a net liability of $34.9 million at December 31, 2005 to a net asset of $3.4 million at December 31, 2006 due to the settlement of 2006 collars and swaps, premiums paid in 2006 to enter into puts and collars with better than market terms, and lower prices for natural gas (in thousands):

	December 31, 2005	December 31, 2006
	(Successor)	(Successor)
Derivative assets:		
Oil derivative contracts	$ 1,899	$ 1,658
Gas derivative contracts	1,561	17,281
Derivative liabilities:		
Oil derivative contracts	(26,540)	(8,905)
Gas derivative contracts	(11,849)	(6,600)
Net derivative asset (liability)	$(34,929)	$ 3,434

As of December 31, 2006, an unrealized derivative fair value loss of $4.0 million ($2.5 million after tax), related to cash flow hedges, was recorded in accumulated other comprehensive loss. Based on the estimated fair values of derivative contracts that qualify for cash flow hedge accounting at December 31, 2006, the Company expects to reclassify net losses of $3.2 million ($1.9 million after tax) out of accumulated other comprehensive loss into earnings during the next twelve months. However, actual gains or losses may vary materially based on actual prices at the contract settlement dates.

Crude Oil Agreements. As of December 31, 2006, the Company has 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, 2006 for production:				
January 1—December 31, 2007	7,313	$49.72	6,115	$71.58
January 1—December 31, 2008	4,950	$54.43	4,950	$75.38
January 1—December 31, 2009	4,580	$53.94	4,580	$76.78
January 1—December 31, 2010	4,500	$60.00	4,500	$72.96

Natural Gas Agreements. As of December 31, 2006, 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, 2006 for production:				
January 1—December 31, 2007	21,000	$6.93	15,436	$10.78
January 1—December 31, 2008	13,500	$7.48	11,947	$11.65
January 1—December 31, 2009	9,500	$7.61	9,500	$12.10
January 1—December 31, 2010	10,000	$7.22	10.000	$10.57

The Company had entered into a forward sales contract with a gas purchaser under which it was obligated for physical delivery of specified volumes of gas with a floor price through December 2006. As this contract provided for physical delivery of the gas, it was not considered a derivative because it had been designated as a normal sale.

In February 2007, the Company entered into additional derivative contracts for crude oil and natural gas production from April 1, 2007 through December 31, 2010. The average production and maximum and minimum prices from the contracts are summarized below:

Crude Oil Agreements

	Minimum		Maximum	
	Barrels/day	**Avg. Prices**	**Barrels/day**	**Avg. Prices**
Crude oil derivatives for production:				
April 1—December 31, 2007	2,000	$57.00	2,000	$73.55
January 1—December 31, 2008	2,500	$67.25	2,500	$67.25
January 1—December 31, 2009	2,000	$67.22	2,000	$67.22
January 1—December 31, 2010	1,000	$66.75	1,000	$66.75

Natural Gas Agreements

	Minimum		Maximum	
	MMBtu/Day	**Avg. Prices**	**MMBtu/Day**	**Avg. Prices**
Natural gas derivatives for production:				
April 1—December 31, 2007	11,500	$7.50	11,500	$10.35
January 1—December 31, 2008	5,700	$7.75	5,700	$10.05
January 1—December 31, 2009	4,000	$7.30	4,000	$ 9.85
January 1—December 31, 2010	1,000	$7.00	1,000	$ 9.10

The Company entered into an interest rate swap transaction during 2006 to lock in its interest cost on $200 million of borrowings at a fixed rate of 9.9225%, including a 4.5% margin, through May 2008.

The Company pays a fixed interest rate of 5.4225% and receives a floating interest rate based on the three-month LIBOR rate. Settlements are made quarterly. The Company has not designated this interest rate swap as a hedge. The fair value of the interest rate swap of $0.5 million at December 31, 2006 has been recorded in accrued liabilities with a corresponding unrealized loss in interest expense.

6. 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 properties (including removal of certain onshore and offshore facilities in California) at the end of their productive lives in accordance with applicable state and federal laws. The Company determines asset retirement 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 over the productive life of the related assets. Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or decrease in the asset retirement obligation and the related capitalized asset retirement costs. Capitalized costs are 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, 2005 and 2006 (in thousands):

	2005 (Successor)	2006 (Successor)
Asset retirement obligations at beginning of period	$23,390	$22,757
Revisions of estimated liabilities	(3,083)	4,214
Liabilities incurred	1,267	13,372
Liabilities settled	(569)	(836)
Accretion expense	1,752	2,542
Asset retirement obligations at end of period	22,757	42,049
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	(108)	(3,065)
Long-term asset retirement obligations	$22,649	$38,984

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 6% and 8%. The 2005 revisions primarily relate to extensions in the timing of obligations based on reserve evaluations. The 2006 revisions primarily relate to updated estimates for expected cash outflows and reductions in the timing of obligations based on reserve evaluations. Liabilities incurred in 2006 include $11.1 million of asset retirement obligations attributable to the acquisition of TexCal.

7. 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 provision for income taxes is composed of the following (in thousands):

	2004 (Predecessor)	2005 (Successor)	2006 (Successor)
Current:			
Federal	$ 4,229	$ 9,700	$ 580
State	1,250	3,300	30
Deferred	10,609	(2,700)	15,040
Total provision for income taxes	$16,088	$10,300	$15,650

A reconciliation of the Company's federal statutory rate of 35% to the Company's effective income tax rate is as follows (in thousands):

	2004 (Predecessor)	2005 (Successor)	2006 (Successor)
Income tax expense at federal statutory rate	$13,506	$ 9,200	$13,860
State income taxes	1,791	1,300	1,424
Other	791	(200)	366
	$16,088	$10,300	$15,650

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

	December 31,	
	2005 (Successor)	2006 (Successor)
Deferred income tax assets:		
Accrued liabilities	$ 786	$ 521
Unrealized hedging losses	22,070	4,913
Share-based compensation	—	1,177
Bad debts	303	306
Unrealized interest rate swap losses	—	191
State tax benefit	1,053	11
Alternative minimum tax credits	12	55
Other	175	264
	24,399	7,438
Deferred income tax liabilities:		
Oil and natural gas properties	(38,636)	(45,469)
Prepaid expenses	(1,260)	(1,514)
	(39,896)	(46,983)
Net deferred income tax liabilities	(15,497)	(39,545)
Net current deferred tax asset	8,611	879
Noncurrent deferred tax liability	$(24,108)	$(40,424)

The Company's federal income tax returns for the 2003 and 2004 tax years are currently under examination by the U.S. Internal Revenue Service ("IRS"). A Notice of Proposed Adjustments (NOPA) was issued by the IRS in June 2006 for the 2003 tax year. The IRS has informed the Company that it plans to combine the 2003 and 2004 examination results in one final report. The Company does not expect to receive the final report until the 2004 examination is complete. The Company anticipates completion of the 2004 examination and receipt of the final report in 2007. In the NOPA for the 2003 tax year, the IRS is proposing 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. The Company disagrees with the IRS proposed assessment and anticipates filing a response with the IRS to protest the proposed adjustments. The Company believes that a resolution of the proposed adjustments could result in a reclassification of between $1,000,000 and $2,300,000 between current and deferred income tax expense and would have no impact on the Company's net income. In the opinion of management, the ultimate resolution of this matter will not have a material impact on the Company's results of operations or financial position.

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.

8. CAPITAL STOCK AND TRANSACTIONS WITH SHAREHOLDER

The Company issued 6,000 shares of mandatorily redeemable convertible non-participating preferred stock in 1998 for $10,000 per share. The shares were mandatorily redeemable in 2009 at $10,000 per share and accrued dividends at an 8 percent annual cash dividend rate, payable quarterly. In November 2004, the Company repurchased all of the outstanding preferred stock, consisting of 6,000 shares of preferred stock plus accrued and unpaid dividends, for $72 million. At the time of the purchase of the preferred stock, the Company had recorded preferred stock and accrued but unpaid dividends net of unamortized issuance costs of $101.9 million. Additional paid-in capital was increased by the excess of the carrying value of the preferred stock over the repurchase price of $29.9 million. No preferred stock was authorized, issued or outstanding as of December 31, 2005 and 2006.

The Company has 48,496,963 shares of common stock issued or reserved for issuance at December 31, 2006 including 5,714,000 shares reserved for issuance under the Company's stock incentive plans. All of the Company's outstanding common stock was controlled by the Company's CEO from December 22, 2004 until August 2006 when the Company's then sole stockholder donated shares of stock to two charitable institutions.

On January 3, 2005, a dividend of $35 million was paid to the Company's then sole stockholder, a trust controlled by the Company's CEO, from the proceeds of the issuance of the senior notes.

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 lease for the office building, which was also transferred in connection with this transaction, includes future minimum lease payments of approximately $1.1 million per year through 2019. Net rent expense and other common area maintenance, improvements, repairs, insurance and taxes paid in 2006 after the dividend date were $1.1 million.

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 has a 20-year term, the Company will lease the property for use in its oil and gas operations for rent of $1 per year. The stockholder's affiliate has 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 is requested, the Company estimates that it will incur approximately $10 million in capital cost to acquire and install new equipment to effect the consolidation. After the consolidation is completed, the Company has 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 will be amortized over the expected life of the ground lease of 20 years.

In 2006, the Company donated approximately $900,000 to a number of educational, medical and other charitable organizations primarily in the Santa Barbara, California and Denver, Colorado areas. Of the total charitable contributions in 2006, approximately $220,000 went to the Denver Scholarship Foundation, a non-profit corporation dedicated to providing college scholarships and related assistance to graduates of Denver public schools. Timothy Marquez is the President and Chairman of the Denver Scholarship Foundation.

9. SHARE-BASED PAYMENTS

During 2005 and 2006, the Company granted options to certain employees and officers of the Company other than Mr. Marquez. Total options granted in 2005 and 2006 were 4,740,663 with a weighted average exercise price of $8.55 ($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 will become immediately vested following 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 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.

Prior to January 1, 2006, the Company accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. Under APB Opinion No. 25, no compensation expense was recognized for stock options issued to employees if the grant price equaled or exceeded the market price on the date of the option grant. Effective January 1, 2006, the Company adopted the provisions of 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 also requires the recognition of the equity component of deferred compensation as additional paid-in capital.

In accordance with the provisions of SFAS 123R, the Company recognized total stock-based compensation cost in the amount of $3.1 million for the year ended December 31, 2006 including $2.8 million as general and administrative expense and $0.3 million as oil and natural gas production expense. No income tax benefit was recognized in 2006 related to the Company's share based payment arrangements. SFAS 123R 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. The cumulative adjustment from adopting SFAS 123R as of January 1, 2006 to include estimated forfeitures in the calculation was not material and had no impact on earnings per share.

The following summarizes the Company's stock option activity for the years ended December 31, 2004, 2005 and 2006:

	Year Ended December 31,						
	2004		2005		2006		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value of Options (in thousands)
Outstanding, start of period	403,515	$3.48	—	—	4,013,663	$ 7.04	
Granted	—		4,013,663	$7.04	727,000	$16.85	
Exercised	(78,188)	$2.22	—	—	—	—	
Cancelled	(325,327)	$3.78	—	—	—	—	
Outstanding, end of period	—	—	4,013,663	$7.04	4,740,663	$ 8.55	$14,229
Exercisable, end of period	—	—	802,732	$7.04	1,750,865	$ 7.86	$ 6,827
Vested or expected to vest at end of year	—		802,732		1,750,865		$ 6,827
Weighted average grant-date fair value of options granted during the period		$ —		$2.79		$ 6.45	

As of December 31, 2006, there was $7.4 million of total unrecognized compensation cost related to stock options which is expected to be amortized over a weighted-average period of 3.0 years.

Additional information related to options outstanding at December 31, 2006 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	2,995,200	8.2 years	$ 6.12	1,198,080	8.2	$ 6.12
$8.00-$8.68	560,963	8.3 years	$ 8.33	224,385	8.3	$ 8.33
$10.67-$13.33	497,500	8.7 years	$11.53	191,000	8.7	$11.51
$15.00-$20.00	687,000	9.7 years	$17.13	137,400	9.7	$17.13
	4,740,663	8.5 years	$ 8.55	1,750,865	8.4	$ 7.86

Non-vested stock options	Shares	Weighted-Average Grant-Date Fair Value
Non-vested at January 1, 2006	3,210,930	$2.79
Granted	727,000	$6.45
Vested	(948,133)	$3.35
Forfeited	—	$ —
Non-vested at December 1, 2006	2,989,798	$3.51

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 2005 and 2006 to compute the weighted average fair market value of options granted during the periods presented:

	Year Ended December 31	
	2005	**2006**
Expected option life	5 years	6 years
Risk free interest rates	3.7%-4.2%	4.3%-4.8%
Estimated volatility	76%	40%
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. On January 1, 2006, the Company began calculating the expected life of options granted using the "simplified method' set forth in Staff Accounting Bulletin 107 (average of vesting period and the term of the option). 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 past five years.

10. COMMITMENTS

Leases—The Company has entered into lease agreements for office space and an office building. As of December 31, 2006, future minimum lease payments under operating leases that have initial or remaining non-cancelable terms in excess of one year are $1,837,000 in 2007, $1,870,000 in 2008, $1,979,000 in 2009, $1,954,000 in 2010, $1,787,000 in 2011 and $11,419,000 thereafter. Net rent expense incurred for office space and the office building was $1.2 million, $0.9 million and $1.8 million in 2004, 2005 and 2006, respectively.

11. 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' counsel has announced plans to appeal the ruling. The Company vigorously defended the actions, and will continue to do so until they are resolved. The Company also has defense and indemnity obligations to certain other defendants in the actions who have asserted claims for indemnity for events occurring after we acquired the property in 1995. In addition, 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 defense and indemnity obligations 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") have taken the position that they are 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. The Beverly Hills Unified School District (the "District"), as an additional insured on those policies, brought a declaratory relief action against two of those insurers in Los Angeles County Superior Court. In November 2005, the court ruled in favor of one of the insurers. On February 16, 2007 an appellate court affirmed the decision of the Superior Court. On July 10, 2006, the same Los Angeles County Superior Court that ruled in favor of one of the insurers denied a motion for summary judgment brought by another of the insurers against the District on the issue of the insurer's duty to defend. On February 10, 2006, the Company filed its own 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. That action is ongoing. The policy issued by the insurer that currently is providing defense of the lawsuits contains a pollution exclusion similar to that at issue in the actions brought against the Declining Insurers. However, 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.

Personal Injury Claims

On February 23, 2006, a complaint was filed in Santa Barbara Superior Court against the Company on behalf of a boy who was severely injured after falling from a cliff located on property jointly owned by the Company and another company. The complaint asserted that the Company is responsible for the boy's injuries and that the boy is entitled to damages, including reimbursement of past medical expenses, future expenses, loss of earning capacity and general damages. In December 2006 a settlement was reached between the plaintiff and the property owners and the case was dismissed on January 8, 2007. The settlement was not material to the Company's financial position or results of operations.

On March 31, 2006, a complaint was filed in District Court in Madison County, Texas against a subsidiary of the Company by the widow of an individual who was killed while working as a gauger/ pumper at a well operated by the subsidiary. The case is scheduled to go to trial in August 2007. The

Company plans to vigorously defend this action. The Company believes that it has legitimate defenses to all allegations in the suit. The Company also believes that it has insurance coverage with respect to the accident. It does not currently believe that it is subject to material exposure in association with this lawsuit. No related liability has been recorded in the Company's consolidated financial statements.

Landowner Dispute

On May 28, 1997, Arch W. Helton and Helton Properties, Inc. and later joined by Linda Barnhill (collectively "Helton parties") filed a lawsuit against Tri-Union Development Corporation ("TDC"), *Helton v. Tri-Union,* in the 80th Judicial District Court of Harris County, Texas, alleging that TDC owed additional royalties on oil and natural gas produced beginning in February 1987 through the initiation of the lawsuit with respect to 18 acres of property in Alvin, Texas. As to the Helton parties largest claim, TDC received a favorable decision from the Texas Railroad Commission, which was upheld by the District Court. The matter was then presented to the United States Bankruptcy Court for the Southern District of Texas, Houston Division in the TDC bankruptcy. After a trial conducted in August and September 2003, the bankruptcy court issued a ruling that resulted in the full avoidance of all of the plaintiffs' claims. The Helton parties have appealed this decision to the 5th Circuit Court of Appeals. Approximately $1.1 million has been segregated pursuant to bankruptcy court order in accordance with the initial plan of reorganization pending resolution of this claim. The Company acquired TDC's interest and claim in the $1.1 million of escrowed funds and the right to defend against any further claims brought by the Helton parties. The Company is confident it will prevail in the Helton appeal.

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.

12. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2005 and 2006 (in thousands except per share data):

	Three Months Ended			
	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
Year Ended December 31, 2005:				
Revenues	$13,957	$40,370	$23,525	$60,101
Net income (loss)	$(6,818)	$ 8,780	$(1,833)	$15,981
Basic earnings (loss) per common share	$ (0.21)	$ 0.27	$ (0.06)	$ 0.49
Diluted earnings (loss) per common share	$ (0.21)	$ 0.27	$ (0.06)	$ 0.48

	Three Months Ended			
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
Year Ended December 31, 2006:				
Revenues	$37,415	$65,573	$98,639	$76,291
Net income	$ 5,107	$ 324	$16,239	$ 2,281
Basic earnings per common share	$ 0.16	$ 0.01	$ 0.50	$ 0.06
Diluted earnings per common share	$ 0.15	$ 0.01	$ 0.47	$ 0.06

Operating results for the quarter ended December 31, 2006 were comparable to the prior two quarters after the TexCal acquisition excluding the effects of realized and unrealized gains and losses on derivative contracts. Future operating results may continue to fluctuate because of the effects that changing commodity prices have on unrealized gains and losses on derivative contracts. In addition, average sales prices per BOE, net of realized hedging losses, were $41.85 for the quarter ended December 31, 2006 vs. average sales prices per BOE of $45.04 for the nine months ended September 30, 2006.

13. 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, 2006, 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 the oil and natural gas reserves at December 31, 2004, and 2005 were estimated by independent petroleum reserve engineers, Netherland, Sewell & Associates, Inc. The evaluations of oil and natural gas reserves for certain properties at December 31, 2006 were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, independent reserve engineers. The following does not include information relating to Marquez Energy for 2004, which is not material.

Capitalized Costs of Oil and Natural Gas Properties

	As of December 31,		
	2004	2005	2006
		(in thousands)	
Properties not subject to amortization:			
Unevaluated costs(1)	$ 384	$ 2,275	$ 4,850
Deposit for purchase of Marquez Energy, LLC(2)	2,000	—	—
	2,384(3)	2,275	4,850
Properties subject to amortization	205,134	267,647	876,720
Total capitalized costs	207,518	269,922	881,570
Accumulated depreciation, depletion and amortization	(45,626)	(66,218)	(127,207)
Net capitalized costs	$161,892	$203,704	$ 754,363

(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 one year.

(2) Amount relates to a deposit made by the Company to the selling members of Marquez Energy in connection with the acquisition of Marquez Energy.

(3) The supplemental information does not include Marquez Energy in 2004. The amount disclosed on the face of the balance sheet (see page F-3 for properties not subject to amortization) does include unproved capital costs from Marquez Energy of $933.

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, 2004, 2005 and 2006 include capitalized general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $2.7 million, $2.5 million and $4.4 million, respectively. Costs incurred also include asset retirement costs incurred of $1.9 million, $1.3 million and $13.4 million during the years ended December 31, 2004, 2005 and 2006, respectively.

	For the year ended December 31,		
	2004	2005	2006
		(in thousands)	
Property acquisition and leasehold costs			
Unevaluated property	$ 129	$ 1,891	$ 2,238
Deposit for purchase of Marquez Energy	2,000	—	—
Proved property	165	10,636	479,112
Exploration costs	2,213	20,592	26,180
Development costs	20,634	62,082	163,005
Total costs incurred	$25,141	$95,201	$670,535

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, 2004, 2005 and 2006.

	Crude Oil, Liquids and Condensate (MBbls)			Natural Gas (MMcf)		
	2004(1)	2005(2)	2006(3)	2004(1)	2005(2)	2006(3)
Beginning of the year reserves	46,757	39,935	35,300	66,585	69,876	74,053
Revisions of previous estimates	(7,357)	(318)	2,580	(9,090)	(6,083)	10,766
Extensions, discoveries and improved recovery	3,636	1,580	935	18,638	7,240	54,061
Purchases of reserves in place	—	2	14,484	—	13,390	105,570
Production	(3,101)	(2,953)	(3,411)	(5,366)	(7,588)	(14,314)
Sales of reserves in place	—	(2,946)	(281)	(891)	(2,782)	(184)
End of year reserves	39,935	35,300	49,607	69,876	74,053	229,952
Proved developed reserves:						
Beginning of year	31,423	28,035	24,154	51,112	49,418	53,390
End of year	28,035	24,154	37,497	49,418	53,390	79,796

(1) Based on unescalated prices of (i) $40.25 per Bbl for oil and natural gas liquids, adjusted for quality, transportation fees and regional price differentials and (ii) $6.18 per MMBtu for natural gas, adjusted for energy content, transportation fees and regional price differentials.

(2) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $10.08 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

(3) Based on unescalated prices of $57.75 per Bbl for oil and natural gas liquids and $5.64 per MMBtu for natural gas, adjusted, in each case, as described in note (1) above.

The Company's estimated proved reserves at year-end December 31, 2005 were approximately 3.9 MMBOE lower than at December 31, 2004. The reduction was due primarily to the Company's sale of the Big Mineral Creek property (partially offset by net reserve acquisitions during the year), depletion that occurred as a result of production and other adjustments based on reservoir information. The Company's estimated proved reserves increased 40.3 MMBOE from December 31, 2005 to

December 31, 2006. The increase was primarily due to the acquisition of TexCal and increases due to extensions and discoveries, partially offset by sales of properties and depletion that occurred as a result of production.

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 the 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 prepared by independent petroleum 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,		
	2004	2005	2006
		(in thousands)	
Future cash inflows	$1,982,599	$2,456,617	$ 3,783,163
Future production costs	(826,527)	(876,858)	(1,485,192)
Future development costs	(146,096)	(163,476)	(441,846)
Future income taxes	(376,618)	(516,416)	(465,412)
Future net cash flows	633,358	899,867	1,390,713
10% annual discount for estimated timing of cash flows	(229,306)	(334,482)	(571,411)
Standardized measure of discounted future net cash flows	$ 404,052	$ 565,385	$ 819,302

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

	As of December 31,		
	2004	2005	2006
		(in thousands)	
Beginning of the year	$ 258,477	$ 404,052	$ 565,385
Revisions to previous estimates:			
Changes in prices and production costs	298,394	332,940	(325,398)
Revisions of previous quantity estimates	(115,876)	(28,544)	59,631
Changes in future development costs	(32,472)	(54,784)	(201,200)
Development costs incurred during the period	18,734	61,404	113,791
Extensions, discoveries and improved recovery, net of related costs	88,056	59,733	135,578
Sales of oil and natural gas, net of production costs	(86,752)	(137,054)	(187,458)
Accretion of discount	39,658	65,308	89,383
Net change in income taxes	(110,920)	(79,418)	26,672
Sale of reserves in place	(1,317)	(73,081)	(5,071)
Purchases of reserves in place	—	47,046	551,774
Production timing and other	48,070	(32,217)	(3,785)
End of year	$ 404,052	$ 565,385	$ 819,302

14. GUARANTOR FINANCIAL INFORMATION

In connection with the issuance of the senior notes in December 2004, BMC, Ltd., Whittier Pipeline Corp. and 217 State Street, Inc. ("Guarantors") fully and unconditionally guaranteed, on a joint and several basis, the Company's obligations under the senior notes. On March 31, 2005, Marquez Energy became a Guarantor of the senior notes. The Company had two subsidiaries, 6267 Carpinteria and Ellwood Pipeline, Inc., that have not been Guarantors (the "Non-Guarantor Subsidiaries"). 6267 Carpinteria ceased being a subsidiary on March 22, 2006. On November 1, 2005, the Company merged Marquez Energy and 217 State Street with and into Venoco, Inc., leaving BMC and Whittier as the only Guarantors until the TexCal Acquisition. On March 31, 2006, TexCal and its four subsidiaries became Guarantors. All Guarantors are 100% owned by the Company. Presented below are the Company's condensed consolidating balance sheets, statements of operations and cash flows as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934. The condensed consolidating financial information for 2004 and 2005 has been revised to reflect the guarantor and non-guarantor status of the Company's subsidiaries at December 31, 2006.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS— YEAR ENDED DECEMBER 31, 2004 (Predecessor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil and natural gas	$131,263	$8,698	$ —	$ —	$139,961
Commodity derivative (losses)	(18,685)	—	—	—	(18,685)
Other	4,079	58	5,946	(4,626)	5,457
Total revenues	116,657	8,756	5,946	(4,626)	126,733
EXPENSES:					
Oil and natural gas production	46,027	2,031	1,509	—	49,567
Transportation expense	7,285	—	—	(4,370)	2,915
Depletion, depreciation, amortization and impairment	15,529	787	173	—	16,489
Accretion of abandonment liability	1,389	71	22	—	1,482
General and administrative, net of amounts capitalized	10,685	630	213	(256)	11,272
Amortization of deferred loan costs	3,050	—	—	—	3,050
Interest, net	3,663	—	(1,394)	—	2,269
Total expenses	87,628	3,519	523	(4,626)	87,044
Equity in subsidiary income	6,216	—	—	(6,216)	—
Income before income taxes	35,245	5,237	5,423	(6,216)	39,689
Income tax expense	11,644	2,246	2,198	—	16,088
Income before minority interest in Marquez Energy	23,601	2,991	3,225	(6,216)	23,601
Minority interest in Marquez Energy	95	—	—	—	95
Net income	$ 23,506	$2,991	$ 3,225	$(6,216)	$ 23,506

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS— YEAR ENDED DECEMBER 31, 2005 (Successor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$186,130	$ 4,962	$ —	$ —	$191,092
Commodity derivative (losses)	(57,595)	—	—	—	(57,595)
Other	3,283	21,670	7,110	(27,607)	4,456
Total revenues	131,818	26,632	7,110	(27,607)	137,953
EXPENSES:					
Oil and natural gas production	51,751	547	1,740	—	54,038
Transportation expense	6,817	—	—	(4,221)	2,596
Depletion, depreciation, amortization and impairment	21,070	313	297	—	21,680
Accretion of abandonment liability	1,663	67	22	—	1,752
General and administrative, net of amounts capitalized	16,950	125	654	(1,722)	16,007
Amortization of deferred loan costs	15,621	(665)	(1,283)	—	13,673
Interest, net	1,755	—	—	—	1,755
Total expenses	115,627	387	1,430	(5,943)	111,501
Equity in subsidiary income	5,987	—	—	(5,987)	—
Income before income taxes	22,178	26,245	5,680	(27,651)	26,452
Income tax provision (benefit)	6,026	10,221	2,211	(8,158)	10,300
Income before minority interest	16,152	16,024	3,469	(19,493)	16,152
Minority interest in Marquez Energy	(42)	—	—	—	(42)
Net income	$ 16,110	$16,024	$ 3,469	$(19,493)	$ 16,110

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

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$194,072	$80,741	$ —	$ —	$274,813
Commodity derivative (losses)	(2,365)	—	—	—	(2,365)
Other	4,716	53	5,227	(4,526)	5,470
Total revenues	196,423	80,794	5,227	(4,526)	277,918
EXPENSES:					
Oil and natural gas production	56,769	28,686	2,050	—	87,505
Transportation expense	7,203	251	—	(3,921)	3,533
Depletion, depreciation and amortization	44,101	19,015	143	—	63,259
Accretion of abandonment liability	1,885	634	23	—	2,542
General and administrative, net of amounts capitalized	27,219	1,389	314	(605)	28,317
Amortization of deferred loan costs	3,776	—	—	—	3,776
Interest, net	51,750	(336)	(2,029)	—	49,385
Total expenses	192,703	49,639	501	(4,526)	238,317
Equity in subsidiary income	21,701	—	—	(21,701)	—
Income before income taxes	25,421	31,155	4,726	(21,701)	39,601
Income tax provision (benefit)	1,470	12,312	1,868	—	15,650
Net income	$ 23,951	$18,843	$ 2,858	$(21,701)	$ 23,951

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2005 (Successor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 9,041	$ —	$ 348	$ —	$ 9,389
Accounts receivable	29,253	490	98	—	29,841
Inventories	1,753	—	—	—	1,753
Commodity derivatives	3,391	—	—	—	3,391
Prepaid expenses and other current assets	3,894	—	457	—	4,351
Income taxes receivable	4,107	—	—	—	4,107
Deferred income taxes	8,611	—	—	—	8,611
TOTAL CURRENT ASSETS	60,050	490	903	—	61,443
PROPERTY, PLANT & EQUIPMENT, NET	222,798	17,756	14,868	(21,646)	233,776
COMMODITY DERIVATIVES	69	—	—	—	69
INVESTMENTS IN AFFILIATES	69,651	—	—	(69,651)	—
OTHER	7,270	—	—	—	7,270
TOTAL ASSETS	$359,838	$ 18,246	$ 15,771	$(91,297)	$302,558
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 31,784	10	60	—	$ 31,854
Undistributed revenue payable	2,155	—	—	—	2,155
Current maturities of long-term debt	—	—	126	—	126
Commodity derivatives	26,397	—	—	—	26,397
TOTAL CURRENT LIABILITIES	60,336	10	186	—	60,532
LONG-TERM DEBT	169,180	—	9,763	—	178,943
DEFERRED INCOME TAXES	24,108	—	—	—	24,108
ASSET RETIREMENT OBLIGATIONS	21,507	701	441	—	22,649
INTERCOMPANY PAYABLES (RECEIVABLES)	68,381	(49,325)	(19,056)	—	—
OTHER LIABILITIES	11,992	—	—	—	11,992
TOTAL LIABILITIES	355,504	(48,614)	(8,666)	—	298,224
TOTAL STOCKHOLDERS' EQUITY	4,334	66,860	24,437	(91,297)	4,334
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$359,838	$ 18,246	$ 15,771	$(91,297)	$302,558

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2006 (Successor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (12)	$ 8,358	$ 18	$ —	$ 8,364
Accounts receivable	24,894	23,026	122	—	48,042
Inventories	3,150	61	—	—	3,211
Prepaid expenses and other current assets	5,753	1,473	—	—	7,226
Income taxes receivable	8,098	—	—	—	8,098
Deferred income taxes	879	—	—	—	879
Commodity derivatives	10,348	—	—	—	10,348
TOTAL CURRENT ASSETS	53,110	32,918	140	—	86,168
PROPERTY, PLANT & EQUIPMENT, NET	363,947	431,198	772	(21,664)	774,253
COMMODITY DERIVATIVES	8,591	—	—	—	8,591
INVESTMENTS IN AFFILIATES	562,104	—	—	(562,104)	—
OTHER	18,413	5,768	—	—	24,181
TOTAL ASSETS	$1,006,165	$ 469,884	$ 912	$(583,768)	$893,193
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 48,319	$ 5,581	$ —	$ —	$ 53,900
Undistributed revenue payable	7,831	7,765	—	—	15,596
Interest payable	5,300	(5)	—	—	5,295
Current maturities of long-term debt	3,557	—	—	—	3,557
Commodity derivatives	8,574	—	—	—	8,574
TOTAL CURRENT LIABILITIES:	73,581	13,341	—	—	86,922
LONG-TERM DEBT	529,616	—	—	—	529,616
DEFERRED INCOME TAXES	40,424	—	—	—	40,424
COMMODITY DERIVATIVES	6,931	—	—	—	6,931
ASSET RETIREMENT OBLIGATIONS	29,296	9,408	280	—	38,984
INTERCOMPANY PAYABLES (RECEIVABLES)	136,001	(104,837)	(31,164)	—	—
TOTAL LIABILITIES	815,849	(82,088)	(30,884)	—	702,877
TOTAL STOCKHOLDERS' EQUITY	190,316	551,972	31,796	(583,768)	190,316
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,006,165	$ 469,884	$ 912	$(583,768)	$893,193

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2004 (Predecessor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net cash provided by operating activities	$ 32,092	$ 6,094	$ 5,123	$ —	$ 43,309
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(15,449)	(684)	(213)	—	(16,346)
Expenditures for other property and equipment	(245)	(16)	—	—	(261)
Purchase of new building	—	—	(14,653)	—	(14,653)
Proceeds from sale of oil and natural gas properties	1,526	—	—	—	1,526
Proceeds from sale of other property and equipment	—	—	228	—	228
Acquisition of Marquez Energy	(672)	—	—	—	(672)
Notes receivable—officers and employees	2,188	—	—	—	2,188
Net cash used in investing activities	(12,652)	(700)	(14,638)	—	(27,990)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from intercompany borrowings	5,815	(5,394)	(421)	—	—
Proceeds from long-term debt	262,397	—	10,000	—	272,397
Principal payments on long-term debt	(159,595)	—	(59)	—	(159,654)
Increase in deferred loan costs	(9,653)	—	—	—	(9,653)
Purchase of preferred stock and unpaid dividends	(72,000)	—	—	—	(72,000)
Contributions from Marquez Energy members	500	—	—	—	500
Distribution payments to Marquez Energy members	(611)	—	—	—	(611)
Net cash (used in) provided by financing activities	26,853	(5,394)	9,520	—	30,979
Net increase in cash and cash equivalents	46,293	—	5	—	46,298
Cash and cash equivalents, beginning of period	8,372	—	45	—	8,417
Cash and cash equivalents, end of period	$ 54,665	$ —	$ 50	$ —	$ 54,715

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2005 (Successor)
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net cash provided by operating activities	$ 27,873	$ 6,174	$ 5,884	$ —	$ 39,931
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(72,217)	(16,068)	(8)	—	(88,293)
Expenditures for other property and equipment	(1,813)	—	—	—	(1,813)
Proceeds from sale of oil and natural gas properties	—	44,619	—	—	44,619
Acquisition of Marquez Energy, LLC	(14,628)	—	—	—	(14,628)
Notes receivable—officers and employees	—	1,420	—	—	1,420
Net cash (used in) provided by investing activities	(88,658)	29,971	(8)	—	(58,695)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	37,869	(32,344)	(5,525)	—	—
Proceeds from long-term debt	59,000	—	—	—	59,000
Principal payments on long-term debt	(39,000)	(4,684)	(53)	—	(43,737)
Increase in deferred loan costs	(817)	—	—	—	(817)
Payments of dividends	(35,000)	—	—	—	(35,000)
Distribution payments to Marquez Energy member	—	(707)	—	—	(707)
Repurchase common stock	(5,301)	—	—	—	(5,301)
Net cash (used in) provided by financing activities	16,751	(37,735)	(5,578)	—	(26,562)
Net (decrease) increase in cash and cash equivalents	(44,034)	(1,590)	298	—	(45,326)
Cash and cash equivalents, beginning of period	53,075	1,590	50	—	54,715
Cash and cash equivalents, end of period	$ 9,041	$ —	$ 348	$ —	$ 9,389

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

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 83,447	$ 7,193	$(1,550)	$ —	$ 89,090
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(157,855)	(27,354)	—	—	(185,209)
Proceeds from sale of oil and natural gas properties	5,533	40,856	—	—	46,389
Investment in Texcal, net of cash acquired	(456,810)	9,291	—	—	(447,519)
Expenditures for property and equipment and other	(8,708)	(157)	—	—	(8,865)
Net cash used in investing activities	(617,840)	22,636	—	—	(595,204)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	20,218	(21,471)	1,253	—	—
Proceeds from long-term debt	569,529	—	—	—	569,529
Principal payments on long-term debt	(210,068)	—	(33)	—	(210,101)
Dividend paid to shareholder	(426)	—	—	—	(426)
Deferred loan costs	(15,335)	—	—	—	(15,335)
Proceeds from derivative premium financing	3,903	—	—	—	3,903
Proceeds from issuance of common shares	160,393	—	—	—	160,393
Payments for stock issuance costs	(2,874)	—	—	—	(2,874)
Net cash provided by financing activities	525,340	(21,471)	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

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DIRECTORS AND OFFICERS

Timothy Marquez
Chairman and Chief Executive Officer

William Schneider
President

Timothy A. Ficker
Chief Financial Officer

Mark DePuy
Executive Vice President and Chief Operating Officer

Terry L. Anderson
General Counsel and Secretary

Douglas Griggs
Chief Accounting Officer

Carla J. Wolin
Chief Human Resources Officer

Ed O'Donnell
Senior Vice President, Coastal California

Jeffrey Janik
Senior Vice President, Texas Operations

Terry Sherban
Vice President, Acquisitions

Gregory B. Schrage
Vice President, Asset Development

Roger K. Hamson
Vice President, Coastal Operations

Kevin Morrato
Vice President, Sacramento Basin Operations

Michael G. Edwards
Vice President, Government and Public Affairs

J. Timothy Brittan
Director

J.C. "Mac" McFarland
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(713) 533-4000

AUDITORS

Deloitte & Touche LLP
Certified Public Accountants
Denver, Colorado

LEGAL COUNSEL

Davis Graham & Stubbs LLP
Denver, Colorado

INDEPENDENT RESERVOIR ENGINEERS

Netherland, Sewell & Associates, Inc.
Dallas, Texas

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 your shareholder account.

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 2006 (including financial statements and schedules but excluding exhibits) to any stockholder who requests one. Requests should be directed to Venoco, Inc., Attn: Secretary, 6267 Carpinteria Avenue, Suite 100, Carpinteria, California 93013. Copies of the 10-K and all exhibits thereto can also be obtained from our website.

CODE OF BUSINESS CONDUCT AND ETHICS

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

ANNUAL MEETING

The annual meeting of shareholders of Venoco, Inc. will be held at the Brown Palace Hotel, 321 17th Street, Denver, Colorado on May 23, 2007, at 7:30 a.m.

VENOCO, INC

370 17TH STREET, SUITE 3900
DENVER, CO 80202-1370
TEL: (303) 626-8300
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