Venoco, Inc. (VQ)

10-K
Annual report pursuant to section 13 and 15(d)
Filed on 02/16/2012
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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, 2011

☐ **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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

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

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

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

The aggregate market value of the registrant's common stock held by non-affiliates of the registrant on June 30, 2011 was $379.7 million, based on the closing price as reported on the New York Stock Exchange (treating, for this purpose, all executive officers and directors of the registrant, and a charitable foundation associated with the registrant's chief executive officer, as affiliates). There were 61,596,405 shares of common stock outstanding as of December 31, 2011.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its 2012 Annual Meeting of Stockholders or an amendment to this report to be filed no later than 120 days after the close of the registrant's fiscal year.

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FORWARD-LOOKING STATEMENTS

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

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

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

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

- changes in oil and natural gas prices, including reductions in prices that would adversely affect our revenues, income, cash flow from operations, liquidity and reserves;
- adverse conditions in global credit markets and in economic conditions generally;
- risks related to our level of indebtedness;
- our ability to replace oil and natural gas reserves;
- risks arising out of our hedging transactions;
- our inability to access oil and natural gas markets due to operational impediments;
- uninsured or underinsured losses in, or operational problems affecting, our oil and natural gas operations;
- inaccuracy in reserve estimates and expected production rates;
- exploitation, development and exploration results, including in the onshore Monterey shale, where our results will depend on, among other things, our ability to identify productive intervals and drilling and completion techniques necessary to achieve commercial production from those intervals;
- the consequences of changes we may make from time to time to our capital expenditure budget, including the impact of those changes on our production levels, reserves, results of operations and liquidity;
- our ability to manage expenses, including expenses associated with asset retirement obligations;
- a lack of available capital and financing, including as a result of a reduction in the borrowing base under our revolving credit facility;
- 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;
- the effect of any business combination, joint venture or other significant transaction we may pursue, or the costs of litigation related thereto;
- the risk that the conditions to the proposed merger of us with an affiliate of Mr. Marquez will not be satisfied;
- factors affecting the nature and timing of our capital expenditures;
- the impact and costs related to compliance with or changes in laws or regulations governing or affecting our operations, including changes resulting from the Deepwater Horizon well blowout in the Gulf of Mexico, from the Dodd-Frank Wall Street Reform and Consumer Protection Act or its implementing regulations and from regulations relating to greenhouse gas emissions;

- delays, denials or other problems relating to our receipt of operational consents and approvals from governmental entities and other parties;
- environmental liabilities;
- loss of senior management or technical personnel;
- natural disasters, including severe weather;
- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us;
- risk factors discussed in this report; and
- other factors, many of which are beyond our control.

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GLOSSARY OF TECHNICAL TERMS

3D and 2D seismic	3D seismic data is geophysical data that depicts the subsurface strata in three dimensions. 3D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional, or 2D, seismic data.
Anticline	An arch-shaped fold in rock in which rock layers are upwardly convex.
Bbl	One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbon.
Bcf	One billion cubic feet of natural gas.
Bcfe	One billion cubic feet of natural gas equivalent, using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.
BOE	One stock tank barrel of oil equivalent, using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.
Btu	British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.
Condensate	A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
/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.
Enhanced recovery project	A project involving injected fluid support to facilitate increased hydrocarbon recovery, including through the use of water, CO_2 or steam.
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.

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Exploration well	Means "exploratory well" as defined in Rule 4-10 of SEC Regulation S-X and refers to a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.
Gross acres or gross wells	The total acres or wells, as applicable, in which a working interest is owned.
Infill drilling	Drilling of an additional well or wells at less than existing spacing to more adequately drain a reservoir.
Injection well	A well in which water is injected, the primary objective typically being to maintain reservoir pressure.
MBbl	One thousand barrels.
MBOE	One thousand BOEs.
Mcf	One thousand cubic feet of natural gas. For the purposes of this report, this volume is stated at the legal pressure base of the state or area in which the reserves are located and at 60 degrees Fahrenheit.
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.
MMcfe	One million 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.
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.
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.

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Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, or for which the cost of the required equipment is relatively minor compared to the cost of a new well.
Proved developed reserves to production ratio	The ratio of proved developed reserves to total net production for the fourth quarter of the relevant year or other specified period.
Proved developed producing reserves	Reserves that are being recovered through existing wells with existing equipment and operating methods.
Proved reserves or proved oil and gas reserves	This term means "proved oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X and refers to the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.
Proved reserves to production ratio	The ratio of total proved reserves to total net production for the fourth quarter of the relevant year or other specified period.
Proved undeveloped reserves or PUDs	Undeveloped reserves that qualify as proved reserves.
PV-10	The PV-10 of reserves is the present value of estimated future revenues to be generated from the production of the reserves net of estimated production and future development costs and future plugging and abandonment costs, using the twelve-month arithmetic average of the first of the month prices, without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, without non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and income taxes, and discounted using an annual discount rate of 10%.
Recompletion	The completion for production of an existing wellbore in a different formation or producing horizon, either deeper or shallower, from that in which the well was previously completed.

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Reserves	This term is defined in Rule 4-10 of SEC Regulation S-X and refers to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
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.
Spacing	The number of wells which can be drilled on a given area of land under applicable regulations.
Undeveloped acreage	Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether the acreage contains proved oil and natural gas reserves.
Undeveloped reserves	Means "undeveloped oil and gas reserves" as is defined in Rule 4-10 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.
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 producing properties are located both onshore and offshore Southern California and onshore in California's Sacramento Basin, and are characterized by long reserve lives, predictable production profiles and substantial opportunities for further exploitation and development. We are also pursuing a major exploration and development project targeting the onshore Monterey shale formation in Southern California.

We are one of the largest independent oil and natural gas companies in California based on production volumes. According to a reserve report prepared by DeGolyer & MacNaughton, we had proved reserves of approximately 95.9 MMBOE as of December 31, 2011, based on adjusted prices of $99.62 per Bbl for oil and $4.05 per MMBtu for natural gas. As of that date, 49% of our proved reserves were oil and 51% were proved developed, and the PV-10 of those reserves was approximately $1.8 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." Our average net production in 2011 was 17,612 BOE/d.

The following table summarizes certain information concerning our production in 2011 and our reserves and inventory of drilling locations as of December 31, 2011.

	2011 Net Production			Proved Reserves(1)			
	Oil (MBbl)	Gas (MMCF)	(MBOE)	Total (MMBOE)	% Oil	PV-10 ($MM)	Drilling Locations(2)
Southern California	2,438	1,066	2,616	50.4	93%	$1,576	56
Sacramento Basin	3	22,857	3,812	44.9	0%	$ 223	734
Texas	—	—	—	0.6	100%	$ 8	—
Total	2,441	23,923	6,428	95.9	49%	$1,807	790

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $96.19 per Bbl for oil and natural gas liquids and $4.12 per MMBtu for natural gas were adjusted for regional price differentials and other factors to arrive at prices of $99.62 per Bbl for oil, $68.40 per Bbl for natural gas liquids and $4.05 per MMBtu for natural gas, which were used in the calculation of proved reserves at December 31, 2011.

(2) Represents total gross drilling locations identified by management as of December 31, 2011, including 15 probable onshore Monterey shale drilling locations at the Sevier field, but excluding other potential onshore Monterey shale drilling locations. Of the total shown, 321 locations are classified as proved.

Our Strengths

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

High quality asset base with a long reserve life and growth potential. Most of our reserves are located in fields that have large volumes of hydrocarbons in place in multiple geologic horizons. One of our primary objectives is to use our engineering expertise to improve recovery rates from these fields and thereby increase our production and reserves. Our offshore Southern California fields generally have well-established production histories and exhibit relatively moderate production declines. As of December 31, 2011, our proved reserves to production ratio was 15 years based on production during the fourth quarter of 2011. In addition, because our producing properties typically have substantial volumes of remaining hydrocarbons, they provide significant potential upside in proved reserves. We believe that we can develop additional reserves from these properties on a cost effective basis with relatively limited risk. As of December 31, 2011, we had identified 775 drilling locations on our legacy Southern California and Sacramento Basin properties and 15 probable onshore Monterey shale locations at the Sevier field. We anticipate identifying additional locations as we pursue our exploitation and development activities.

Extensive knowledge of the Monterey shale formation and substantial onshore Monterey acreage. A substantial portion of our production is from offshore wells targeting the fractured Monterey shale formation. 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 shale formation onshore as well, and that our offshore expertise will help us take advantage of those opportunities. To date, our onshore Monterey shale acreage position is approximately 256,000 gross and 170,000 net acres. An additional 60,000 gross and 46,000 net acres with Monterey shale production or potential are held by production. We began drilling wells targeting the onshore Monterey shale in 2010, and have drilled over 20 wells since then, significantly advancing our knowledge of the formation. In the near term we intend to focus our efforts on the Sevier field in the San Joaquin valley where we have experienced the most success to date.

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. We have drilled approximately 500 wells in the basin in the last five years and we are currently one of the largest operators there in terms of production and acreage. 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 favorable historical differential to NYMEX prices received for natural gas produced there contribute to the value of our position.

Substantial operational flexibility. We have substantial flexibility in adapting our activities to respond to changes in commodity prices and business conditions generally. We have relatively few medium and long-term drilling commitments and are therefore capable of deferring a large portion of our capital expenditures and/or shifting those expenditures between natural gas and oil-oriented projects as commodity prices dictate. In addition, we have operating control of substantially all of our properties, which allows us 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 and the onshore facility associated with our South Ellwood field. Additionally, the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement presented us with the Safety Award for Excellence for our offshore operations in the Santa Clara Federal Unit, recognizing us as the top operator in the Pacific Outer Continental Shelf in 2008. 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.

Experienced, proven management and operations team. The members of our management team have an average of over 25 years of experience in the oil and natural gas industry. Prior to founding our company in 1992, our CEO, Timothy Marquez, worked for Unocal for 13 years in both engineering and managerial positions. Our operations team has significant experience in the California oil and natural gas industry across a broad range of disciplines, including geology, drilling and operations, and regulatory and environmental matters. Our team includes 55 engineers and geoscientists as of December 31, 2011. We believe that our experience and knowledge of the California oil and natural gas industry are important competitive advantages for us.

Our Strategy

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

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. We intend to continue to take advantage of development opportunities in the Sockeye, South Ellwood, West Montalvo and other California fields that have these characteristics. 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.

Explore and develop the onshore Monterey shale formation. We plan to use the expertise we have developed with the fractured Monterey shale formation from our work in the offshore South Ellwood and Sockeye fields to facilitate our acquisition, exploration, exploitation and development of onshore properties with similar characteristics. We plan to devote approximately 39% of our $255 million capital expenditure budget for 2012, or $100 million, on activities targeting the onshore Monterey shale formation, including the drilling of 15 to 20 gross wells in the Sevier field and the acquisition of 3D seismic data in the Sevier and South Salinas fields. We intend to focus our 2012 drilling efforts on the Sevier field and expect modest production from the field in 2012. We also plan to study wells drilled in the past two years to identify zones that we may have overlooked during the initial completion of the well. We have had success completing zones at Sevier that we had not initially identified on the drilling logs. We expect that these recompletions will help us better understand our acreage relating to wells drilled during 2010 and 2011 outside of Sevier.

Maintain a flexible portfolio of development opportunities. Given current depressed natural gas prices and our robust inventory of oil projects, we intend to reduce our drilling activity in the Sacramento Basin for the near term. However, we continue to believe the basin presents significant exploration, exploitation and development opportunities from both conventional and unconventional reservoirs. As one of the largest operators in the basin, we believe that we are well positioned to identify and exploit these opportunities and that in an improved natural gas price environment we would quickly accelerate our development activities.

Maintain an efficient cost structure. We have maintained low lease operating expenses, due in part to the sale of relatively high-cost fields in Texas in 2009 and 2010 and increased efficiencies in a variety of operating areas. In 2010, we began increasing our focus on oil projects and because those projects tend to have higher operating costs than natural gas projects, we expect a slight increase in per BOE production expenses going forward. However, we will continue to focus on our operating cost structure in order to create additional production and processing efficiencies and reduce operational downtime.

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

Description of Properties

Southern California—Legacy Fields

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

The South Ellwood field is approximately seven miles long and is part of a regional east-west trend of similar geologic structures running along the northern flank of the Santa Barbara channel and extending to the Ventura basin. This trend encompasses several fields that, over their respective lifetimes, are each expected to produce over 100 million barrels of oil, according to the California Division of Oil, Gas, and Geothermal Resources. The Monterey shale formation is the primary oil reservoir in the field, producing sour oil with a gravity of approximately 22 degrees. As of December 31, 2011, there were 17 producing wells and five injection wells in the field.

Our processing and transportation facilities at South Ellwood include a common carrier pipeline, an onshore facility, a pier and a marine terminal. We conduct two-phase separation on the drilling platform and the oil/water emulsion is transported by pipeline to the onshore facility for further separation. After separation, the oil is transported to the refinery via a common carrier pipeline operated by our subsidiary Ellwood Pipeline, Inc. Construction of the common carrier pipeline was completed in January 2012; prior to then, the oil was transported to the marine terminal via a common carrier pipeline, and then transported to the refinery by a barge. Natural gas produced at the field is processed at the onshore facility and transported by common carrier pipeline.

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

The Sockeye field structure is a northwest/southeast trending anticline bounded to the north and south by fault systems. The field produces from multiple stacked reservoirs ranging from the Monterey shale, at about 4,000 feet, to the Middle Sespe at approximately 7,000 feet. Other formations include the Upper Topanga, Lower Topanga and Juncal. As of December 31, 2011, there were 20 producing wells and 11 injection wells in the field. The oil produced from the Monterey shale and Upper Topanga is sour with gravities ranging from 12 to 18 degrees. The Lower Topanga and Sespe horizons produce sweet crude with gravities of 26 to 30 degrees. Chevron shut in production at platform Grace in the Santa Clara field in 1997. We primarily use the platform as a launching and receiving facility for pipeline cleaning devices and as an interconnecting pipeline to transport oil and natural gas produced from platform Gail to our onshore plant. In 2011, we returned one well to production at platform Grace.

West Montalvo Field. We acquired the West Montalvo field in Ventura County, California in May 2007. We operate the field and have a 100% working interest. The field, which includes an offshore portion that is developed from onshore locations, produces from the Sespe formation and produces sour oil with gravity of approximately 16 degrees. As of December 31, 2011, there were 29 producing wells and two injection wells in the field. Since acquiring the field, our primary activities have consisted of returning idle wells to production, redrilling existing wells, working over and recompleting existing wells, and upgrading well lift systems and processing facilities.

Dos Cuadras Field. The Dos Cuadras field is located in federal waters approximately five miles offshore California in the Santa Barbara channel. We acquired our 25% non-operated working interest in the western two-thirds of the field from Chevron in February 1999. We have working interests ranging from approximately 17.5% to 25% in the associated onshore facility and pipelines. The field is operated by an unaffiliated third party. Production is transported via pipeline to Los Angeles, California. As of December 31, 2011, there were 87 producing wells and 17 injection wells in the field.

Beverly Hills West Field. The Beverly Hills West field is located in Beverly Hills, California. All drilling and production operations at the field are conducted from a 0.6 acre surface location adjacent to the campus of Beverly Hills high school. We acquired our interest in the field in 1995. We operate the field and have a 100% working interest. As of December 31, 2011, there were 15 producing wells and three injection wells in the field, which produce oil with gravity of approximately 23 degrees. The lease under which we operate the field expires in 2016.

Santa Clara Avenue Field. The Santa Clara Avenue field is located in Ventura County, California. We acquired our interest in this field in 1994 and 1996. We operate the field and have working interests ranging from 43% to 100%. As of December 31, 2011, there were a total of 17 producing wells in the field, which produce oil with gravity of approximately 22 degrees.

Southern California—Onshore Monterey Shale

We have developed an extensive knowledge of the Monterey shale formation through our work at the offshore South Ellwood and Sockeye (Santa Clara Unit) fields and believe the formation holds significant exploration opportunities onshore. Despite production history that dates back to the late 1880s, including in recent years some unconventional production, we believe the development of the unconventional onshore Monterey shale formation has been largely overlooked due to a number of circumstances, including California's unique competitive landscape. Industry majors have dominated the state's significant oil production and prospective undeveloped acreage for several decades with little incentive to explore new reservoirs due to highly favorable economics in their existing fields. We believe the relative scarcity of other independent operators in the area has not only slowed the development of the play, but also delayed the application of current drilling and completion technologies that have helped to advance other unconventional resource plays across the country in recent years.

In 2006 we began actively leasing onshore acreage in Southern California targeting the Monterey shale formation. Our leasing strategy has focused on areas where we believe the Monterey shale will produce light, sweet oil, where the quality and depth of the Monterey shale is expected to be advantageous, and is near existing infrastructure. As of December 31, 2011, our onshore Monterey shale acreage position totaled approximately 166,000 net acres. To date, our onshore Monterey shale acreage position is approximately 170,000 net acres. We expect to acquire additional acreage strategically in and around our existing leasehold. An additional 46,000 net acres with Monterey shale production or potential are held by production at our legacy Southern California fields.

Sevier Field. The Sevier field is located in Kern County along the western edge of the San Joaquin Valley up against California's coastal mountain range. The field is a steeply dipping, northwest-southeast trending anticline with complex geology and is located in close proximity to the Midway Sunset field. Midway Sunset is California's largest producing oil field and is expected to produce nearly 3.5 billion barrels of oil over its productive life. The gross interval of Monterey formation in the field is several thousand feet thick. To date, our acreage position at Sevier is approximately 10,000 net acres.

Sacramento Basin

In terms of historical production, the Sacramento Basin is one of California's most prolific onshore natural gas producing areas not associated with oil production. It is approximately 210 miles long and 60 miles wide and contains a variety of different geologic plays. We own 3D seismic data covering over 1,100 square miles in the basin, and 2D seismic data covering approximately 20,000 line miles. We continue to analyze this data to identify additional exploration, exploitation and development opportunities on our properties. We believe this data will also help us assess acquisition opportunities in the basin. The Forbes formation, from which the majority of our current Sacramento Basin production comes, consists of multiple, isolated, stacked reservoirs. Many of these individual zones are not revealed on drilling logs. Our technical team has been able to identify and complete many of these zones, which has contributed to a more than three-fold increase in production from the basin from 2006 to 2010.

Willows and Greater Grimes Fields. The Willows and Greater Grimes fields are located in Colusa, Glenn and Sutter counties north of Sacramento, California. Our combined lease position in these fields was approximately 164,000 net acres as of December 31, 2011. We operate substantially all of the fields and have a volume-weighted average working interest of approximately 94% (based on year end reserves of producing wells). Natural gas production in the Greater Grimes field is from the Forbes, Kione and Guinda formations and production in the Willows field is from the Forbes and Kione formations. Depths range from 2,800 feet in the Willows field to 8,900 feet in the Greater Grimes field. There were 555 producing wells in the fields as of December 31, 2011.

Other Sacramento Basin. We own interests in a number of other fields in Solano, Contra Costa, San Joaquin and Colusa counties. We operate substantially all of these fields and have a volume-weighted average working interest of approximately 68% (based on year end reserves of producing wells). As of December 31, 2011, there were a total of 38 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.

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

Texas

We sold our producing assets in Texas in a series of transactions that were completed in the second quarter of 2010 to multiple purchasers for aggregate net proceeds of $98.1 million (after closing adjustments and related expenses). We used the proceeds to repay $66.9 million of principal on our revolving credit facility and $30.7 million of principal on the second lien term loan then in place. We retained our 22.3% reversionary working interest in the Hastings Complex described below. The Texas properties sold comprised 7.2% of our proved reserves at December 31, 2009 or 7.1 MMBOE and contributed approximately 460 BOE/d to our average daily production during 2010.

In February 2009, we sold our interest in properties producing from the Frio formation in the Hastings Complex to Denbury Resources, Inc., or Denbury, for approximately $197.7 million, after certain post-closing adjustments, pursuant to an option agreement we entered into with Denbury in November 2006. The purchase price was in addition to the $50.0 million option payment Denbury previously made to us under the agreement. We retained certain interests in the complex not related to the Frio formation. Substantially all of the current production from the complex is from the Frio formation.

Pursuant to the agreement, Denbury committed to a plan to pursue a CO_2 enhanced recovery project at the properties it acquired. The plan calls for Denbury to make capital expenditures of at least $178.7 million by the end of 2014. As part of the plan, Denbury is responsible for providing the necessary CO_2. We have the right to back in to a working interest of approximately 22.3% in the Hastings Complex 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. If CO_2 recovery operations do not meet certain development milestones by January 2013, Denbury will be required to either resell the properties to us at a discount or make additional payments to us. The agreement also establishes an area of mutual interest with respect to us and Denbury in specified areas adjacent to the properties. The success of the planned CO_2 enhanced recovery project will be subject to numerous risks and uncertainties, including those relating to the geologic suitability of the properties for such a project and the availability of an economic and reliable supply of CO_2. Denbury commenced injecting CO_2 at the complex in December 2010 and began production in January 2012.

Other Exploration

From time to time, we pursue exploration opportunities outside of our core areas that we believe align with our corporate strengths and strategy. Amounts allocated to these types of projects in 2011 were nominal and are expected to be nominal in 2012 as well.

Oil and Natural Gas Reserves

The following table sets forth our net proved reserves as of the dates indicated. Our reserves as of December 31, 2010 and 2011 are set forth in a reserve report prepared by DeGolyer & MacNaughton. DeGolyer & MacNaughton reviews production histories and other geological, economic, ownership and engineering data related to our properties in arriving at their reserve estimates. Proved reserves as of each date indicated reflect all acquisitions and dispositions completed as of that date. A report of

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DeGolyer & MacNaughton regarding its estimates of our proved reserves as of December 31, 2011 has been filed as Exhibit 99.1 to this report.

	Years Ended December 31,	
	2010(1)	2011(2)
Net proved reserves (end of period)		
Oil (MBbl)(3)		
Developed	22,270	25,131
Undeveloped	20,301	22,282
Total	42,571	47,413
Natural gas (MMcf)		
Developed	122,928	141,806
Undeveloped	132,235	149,018
Total	255,163	290,824
Total proved reserves (MBOE)(4)	85,098	95,884
% Oil	50%	49%
% Proved Developed	50%	51%
Proved Reserves to Production Ratio	13 years	15 years
Present Values (thousands):		
Discounted estimated future net cash flow before income taxes (PV-10)(5)	$1,128,696	$1,806,501
Standardized measure of discounted estimated future net cash flow after income taxes (Standardized Measure)	$ 902,901	$1,364,146

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of $96.19 per Bbl for oil and natural gas liquids and $4.12 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at prices of $99.62 per Bbl for oil, $68.40 per Bbl for natural gas liquids and $4.05 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2011.

(3) Our natural gas liquids reserves represent a minimal percentage of our total reserves (approximately 2.8% and 3.1% at December 31, 2010 and 2011, respectively), therefore natural gas liquids are not presented separately but rather are included with oil volumes.

(4) BOE is determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

(5) 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."

Reserves Sensitivity Analysis

The following table sets forth our net proved reserves at December 31, 2011 based on alternative price scenarios as identified below in the footnotes to the table. The following price scenarios illustrate the sensitivity of our estimated reserve quantities under various price assumptions.

	Price Case			
	A (SEC)	B (Strip)	C (SEC -10%)	D (SEC +10%)
Net proved reserves (end of period)				
Oil (MBbl)				
Developed	25,131	25,095	25,059	25,186
Undeveloped	22,282	22,501	22,500	22,500
Total	47,413	47,596	47,559	47,686
Natural gas (MMcf)				
Developed	141,806	144,489	139,585	143,747
Undeveloped	149,018	150,779	147,706	150,077
Total	290,824	295,268	287,291	293,824
Total proved reserves (MBOE)	95,884	96,807	95,441	96,657

A Represents reserves based on pricing prescribed by the SEC. The unescalated twelve month arithmetic average of the first day of the month posted prices were adjusted for quality, energy content, transportation fees and regional price differentials to arrive at prices of $99.62 per Bbl for oil, $68.40 per Bbl for natural gas liquids and $4.05 per MMBtu for natural gas. Production costs were held constant for the life of the wells.

B Prices based on the five year NYMEX forward strip at December 31, 2011, were adjusted as described in note (A) above, resulting in prices which averaged $94.69 per Bbl for oil, $65.01 per Bbl for natural gas liquids and $4.49 per MMBtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case. (The five year NYMEX forward strip represents the futures prices for oil and natural gas as reported on the NYMEX as of December 31, 2011.)

C Prices based on a 10% reduction of the prices used in the year-end SEC case (Price Case A), resulting in prices, adjusted as described in note (A) above, of $89.92 per Bbl for oil, $61.56 per Bbl for natural gas liquids and $3.65 per MMbtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case.

D Prices based on a 10% increase of the prices used in the year-end SEC case (Price Case A), resulting in prices, adjusted as described in note (A) above, of $110.26 per Bbl for oil, $75.24 per Bbl for natural gas liquids and $4.46 per MMbtu for natural gas. Production costs were held constant with the costs as determined in the year-end unescalated SEC reserve case.

Changes in Proved Reserves

Our net proved reserves of 95,884 MBOE as of December 31, 2011 increased 13% from 85,098 MBOE as of December 31, 2010. Our estimated oil and natural gas reserves were principally affected by the following during 2011:

- Extensions and discoveries increased reserves by 16,298 MBOE due to (i) drilling of locations which were not previously classified as proved in the Sacramento Basin and re-evaluation and analysis of data from existing wells which enabled us to identify additional PUD locations and (ii) re-evaluation of the Sockeye field which resulted in additional PUD reserves based on performance of the field;

- Revisions of previous estimates increased reserves by 849 MBOE due to (i) the extension of the estimated life of the South Ellwood field as a result of the approval and completion of the onshore pipeline that replaced the barge operation for transportation of oil production from the field, (ii) better than anticipated drilling success and performance of certain Sacramento Basin fields, (iii) price changes that resulted in a net positive impact and (iv) addition of behind pipe reserves in the Sacramento Basin supported by positive operating results, all of which were largely offset by (i) removal of PUDs not drilled within five years and changes to the timing and focus of PUD development forecasts, and (iii) loss of reserves due to less than expected drilling results and performance, primarily at West Montalvo;

- Purchases of reserves in place increased reserves by 67 MBOE; and

- Current year production decreased reserves by 6,428 MBOE.

Our PUD reserves of 47,119 MBOE as of December 31, 2011 increased 11% from 42,340 MBOE as of December 31, 2010. Our estimated PUDs were principally affected by the following during 2011:

- Extensions, discoveries and improved recovery increased PUDs by 14,537 MBOE due to (i) drilling locations which were not previously classified as proved in the Sacramento Basin and re-evaluation and analysis of data from existing wells which enabled us to identify additional PUD locations and (ii) re-evaluation of the Sockeye field which resulted in additional PUD reserves based on the performance of the field;

- Revisions of previous estimates decreased PUDs by 7,151 MBOE due to (i) removal of PUDs not drilled within five years and changes to the timing and focus of PUD development forecasts and (ii) loss of a portion of reserves related to existing PUDs at West Montalvo due to less than expected drilling results and performance, partially offset by (i) increases in PUDs due to the extension of the estimated life of the South Ellwood field as a result of the approval and completion of the onshore pipeline that replaced the barge operation for transportation of oil production from the field; and

- 2,607 MBOE of reserves classified as proved undeveloped at December 31, 2010 were drilled during the year, primarily at West Montalvo and throughout the Sacramento Basin—capital expenditures related to PUD drilling during 2011 were approximately $20.5 million.

At December 31, 2011, we have no PUDs that are scheduled for development five years or more beyond the date the reserves were initially recorded, except for two PUDs at the Sockeye field which are scheduled to be drilled in the first half of 2012. The wells will be drilled from Platform Gail, which was subject to the deep water drilling moratorium imposed by the Secretary of the U.S. Department of Interior from May 2010 through October 2010 following the Deepwater Horizon well blowout in the Gulf of Mexico. The drilling of these wells was delayed as a result of the moratorium, but were scheduled to be drilled as soon as was practicable after the relevant aspects of the moratorium were lifted. These two PUDs represent approximately 530 MBOE, or 0.6%, of our December 31, 2011 proved reserves. All PUD locations are within one spacing offset of proved locations.

Uncertainties with respect to future acquisition and development of reserves include (i) the success of our development programs, including with respect to the development of the onshore Monterey shale formation and potential changes to our drilling schedule based on ongoing operational results, (ii) our ability to obtain permits from relevant regulatory bodies to pursue development projects, (iii) changes in commodity prices, including potential changes to our drilling schedule if natural gas prices decline further, (iv) the availability of sufficient cash flow from operations or external financing to fund our capital expenditure program, (v) the effect of legislative or regulatory changes on our ability to pursue our hedging strategy, and (vi) the availability and cost of viable acquisition candidates.

As discussed in "Business and Properties—Description of Properties—Texas," Denbury commenced CO_2 injection at the Hastings Complex in December 2010 and began production in January 2012. Once the field demonstrates response to the flood, we expect to record a portion of the proved reserves related to our reversionary interest in the project. Any proved reserves recorded that are attributable to our reversionary interest will be subject to a significant degree of variability until Denbury has recovered all of its costs as defined in the agreement and we are able to back in to our 22.3% working interest. The amount of reserves and resulting production necessary for Denbury to recover its costs will be determined in large part by such factors as the existing commodity prices and operating cost environment.

Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used

Our year-end reserve report is prepared by DeGolyer & MacNaughton in accordance with guidelines established by the SEC. Reserve definitions comply with the definitions provided by Regulation S-X of the SEC. DeGolyer & MacNaughton prepares the reserve report based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information we provide to them. This information is reviewed by knowledgeable members of our company to ensure accuracy and completeness of the data prior to submission to DeGolyer & MacNaughton. Upon analysis and evaluation of data provided, DeGolyer & MacNaughton issues a preliminary appraisal report of our reserves. The preliminary appraisal report and changes in our reserves are reviewed by our Reserves Manager, relevant Reservoir Engineers and Mark DePuy, our Senior Vice President, Business Development and Acquisitions, for completeness of the data presented, reasonableness of the results obtained and compliance with the reserves definitions in Regulation S-X of the SEC. Once all questions have been addressed, DeGolyer & MacNaughton issues the final appraisal report, reflecting its conclusions.

A letter which identifies the professional qualifications of the individual at DeGolyer & MacNaughton who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2011 has been filed as an addendum to Exhibit 99.1 to this report.

Internally, Mr. DePuy is responsible for overseeing our reserves process. He initially joined us in 2005 as Vice President of Northern Assets and was named our Chief Operating Officer the following year. He resigned as our COO in October 2008, but re-joined us in December 2011. Mr. DePuy has over 30 years of experience in the oil and natural gas industry and holds a B.S. in Petroleum Engineering from the Colorado School of Mines and M.B.A from the University of California, Los Angeles.

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

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Production, Prices, Costs and Balance Sheet Information

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. No pro forma adjustments have been made for acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below. The information set forth below is not necessarily indicative of future results.

	Years Ended December 31,		
	2009	2010	2011
Production Volume(1):			
Oil (MBbls)(2)	3,402	2,792	2,441
Natural gas (MMcf)	24,748	23,196	23,923
MBOE(3)	7,527	6,658	6,428
Daily Average Production Volume:			
Oil (Bbls/d)	9,321	7,649	6,688
Natural gas (Mcf/d)	67,803	63,551	65,542
BOE/d(3)	20,622	18,241	17,612
Oil Price per Bbl Produced (in dollars):			
Realized price	$ 50.60	$ 68.86	$ 91.00
Realized commodity derivative gain (loss)	(0.95)	(1.77)	(2.48)
Net realized price	$ 49.65	$ 67.09	$ 88.52
Natural Gas Price per Mcf Produced (in dollars):			
Realized price	$ 3.84	$ 4.34	$ 4.02
Realized commodity derivative gain (loss)	2.58	1.70	1.03
Net realized price	$ 6.42	$ 6.04	$ 5.05
Expense per BOE:			
Lease operating expenses	$ 12.65	$ 12.65	$ 14.64
Production and property taxes	$ 1.35	$ 1.01	$ 0.99
Transportation expenses	$ 0.42	$ 1.37	$ 1.45
Depletion, depreciation and amortization	$ 11.46	$ 11.79	$ 13.35
General and administrative expense, net(4)	$ 4.91	$ 5.64	$ 6.10
Interest expense	$ 5.44	$ 6.10	$ 9.51

(1) The South Ellwood field comprised more than 15% of our total proved reserves as of December 31, 2011. Production from the field was 806 MBbls and 252 MMcf in 2009, 746 MBbls and 93 MMcf in 2010 and 713 MBbls and 288 MMcf in 2011.

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

(3) BOE is determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

(4) Net of amounts capitalized.

Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2009 through December 31, 2011. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross or net wells.

	Development Wells Drilled		
	2009	2010	2011
Productive(1)			
Gross	24.0	30.0	13.0
Net	22.8	28.3	11.4
Dry(2)			
Gross	2.0	5.0	5.0
Net	1.8	5.0	4.8

	Exploration(3) Wells Drilled		
	2009	2010	2011
Productive(1)			
Gross	43.0	55.0	39.0
Net	39.7	50.6	34.3
Dry(2)			
Gross	10.0	11.0	6.0
Net	9.3	10.5	5.9

(1) A productive well is not a dry well, as described below, but a well for which we have set casing. Wells classified as productive, do not always provide economic levels of production.

(2) A dry well is a well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(3) We drill a significant number of wells on non-proved locations in the Sacramento Basin. These wells are considered "exploratory wells" as defined in SEC Regulation S-X and are included in the Exploration Wells Drilled category above. The majority of the wells in the basin that are "exploratory wells" under SEC Regulation S-X are wells drilled on the border of existing fields in an attempt to test and expand the limits of a producing area. We generally do not distinguish between those wells and development wells from an operating perspective. Of the gross productive exploration wells drilled in 2011, 24 were drilled in the Sacramento Basin.

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.

Present Activities

As of December 31, 2011, we were in the process of drilling 2.0 gross (2.0 net) wells and there were 6.0 gross (6.0 net) wells waiting on completion. See "Management's Discussion and Analysis of Financial Condition and Results of Operation—Overview—Capital Expenditures" for additional discussion of our present development activities.

Oil and Natural Gas Wells

The following table details our working interests in producing wells as of December 31, 2011. 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	194.0	125.6	64.7%
Natural gas	595.0	500.2	84.1%
Total(1)	789.0	625.8	79.3%

(1) Amounts shown include 16 oil wells and 4 natural gas wells with multiple completions.

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2011. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped(1)		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Southern California						
South Ellwood	7,682	7,682	—	—	7,682	7,682
Santa Clara Federal Unit	36,000	27,360	—	—	36,000	27,360
Dos Cuadras	5,400	1,350	—	—	5,400	1,350
West Montalvo	3,453	3,453	5,492	5,304	8,945	8,757
Onshore Monterey Shale	10,247	8,134	229,777	157,655	240,024	165,789
Other Southern California	1,524	994	4,168	4,153	5,692	5,147
Total Southern California	64,306	48,973	239,437	167,112	303,743	216,085
Sacramento Basin	135,551	115,685	109,901	88,261	245,452	203,946
Texas	6,967	6,328	—	—	6,967	6,328
Other	67	39	30,915	26,429	30,982	26,468
Total	206,891	171,025	380,253	281,802	587,144	452,827

(1) The percentage of undeveloped acreage held under leases due to expire in 2012, 2013 and 2014, unless extended by exploration or production activities or extension of lease terms, is approximately 5%, 18% and 13%, respectively.

Risk and Insurance Program

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 the risk of well blowouts, oil spills and other adverse events. We could be held responsible for injuries suffered by third parties, contamination, property damage or other losses resulting from these types of events. In addition, we have generally agreed to indemnify our drilling rig contractors against certain of these types of losses. Because of these risks, we maintain insurance against some, but not all, of the potential risks affecting our operations and in coverage amounts and deductible levels that we believe to be economic. Our insurance program is designed to provide us with what we believe to be an economically appropriate level of financial protection from significant unfavorable losses resulting from damages to, or the loss of, physical assets or loss of human life or liability claims of third parties, attributed to certain assets and including such occurrences as well blowouts and resulting oil spills. We regularly review our risks of loss and the cost and availability of insurance and consider the need to revise our insurance program accordingly. Our insurance coverage includes deductibles which must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In general, our current insurance policies covering a blowout or other insurable incident resulting in damage to one of our offshore oil and gas wells provide up to $50 million of well control, pollution cleanup and consequential damages coverage and $250 million of third party liability coverage for additional pollution cleanup and consequential damages, which also covers personal injury and death. The availability and cost of insurance has been impacted by the Gulf of Mexico Deepwater Horizon incident, which occurred in April 2010. In particular, while we have been able to secure our desired level of insurance coverage, we believe that there is less liability insurance coverage available industry-wide and that which is available is more expensive than in the past.

If a well blowout, spill or similar event occurs that is not covered by insurance or not fully protected by insured limits, it could have a material adverse impact on our financial condition, results of operations and cash flows. See "Risk Factors—Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy. We do not have insurance to cover all of the risks that we may face".

Remediation Plans and Procedures

As required by regulations imposed by the Bureau of Ocean Energy Management, Regulation and Enforcement, or BOEMRE, we have updated our existing company oil-spill response plan, we continue to maintain oil spill response equipment on the platforms, including oil spill containment boom and a boat for boom deployment, and have maintained oil-spill financial assurance in connection with our offshore operations. Our oil-spill response plan details procedures for rapid response to spill events that may occur as a result of our operations. The plan calls for training personnel in spill response. Periodically, drills are conducted to measure and maintain the effectiveness of the plan. We review the plan annually and update where necessary.

Also pursuant to BOEMRE regulations, and similar regulations adopted by the California Department of Fish and Game's Office of Oil Spill Prevention and Response, we continue to be a member of Clean Seas, LLC, or Clean Seas, a cooperative entity operated with other offshore operators to effectively respond to oil spills in the offshore region in which we operate. The purpose of Clean Seas is to act as a resource to its member companies by providing an inventory of state-of-the-art oil spill response equipment, trained personnel, and expertise in the planning and execution of response techniques. Clean Seas' equipment consists primarily of oil spill response vessels, including two equipped with approximately 4,500 feet of oil spill containment boom, advanced oil recovery systems, high capacity stationary skimmers, storage tanks for recovered oil, infrared radar and advanced electronic equipment for directing and monitoring oil spill response activities. Clean Seas also recruits and trains local fishermen to assist in oil recovery and the recovery of impacted wildlife. Clean Seas' designated area of response, which encompasses all of our offshore operations, comprises the open oceans and coastline of the South Central Coast of California including Ventura, Santa Barbara, and San Luis Obispo Counties, and the Santa Barbara Channel Islands.

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 current 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.

Indebtedness under our revolving credit facility is 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, Major Customers and Delivery Commitments

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, 2011, approximately 95% of our revenues were generated from sales to four purchasers: ConocoPhillips (66%), Enserco Energy (18%), Calpine Producer Services LP (6%), and Concord Energy LLC (5%). Prospectively, under our new oil sales contracts, a significant portion of our oil production will be sold to Tesoro Refining and Marketing Company. As a result, we expect Tesoro to a be a significant customer in 2012, with a corresponding decrease in sales to ConocoPhillips. 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. We had no material delivery commitments as of February 14, 2012.

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, but are not limited to, Occidental Petroleum Corporation, 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 47,200 net square feet of office space in Denver, Colorado, where our principal office is located. The lease for the Denver office expires in 2014. We lease an additional 51,000 net square feet of office space in Carpinteria, California from 6267 Carpinteria Avenue, LLC. The lease for the Carpinteria office will expire in 2019. 6267 Carpinteria Avenue, LLC was a wholly owned subsidiary of ours prior to March 2006, when we paid a dividend consisting of 100% of the membership interests in 6267 Carpinteria Avenue, LLC to our then-sole stockholder. The lease has remained in effect following the payment of the dividend. Additionally, we lease 7,700 net square feet of office space in Bakersfield, California, the lease for which expires in 2013. We also have leases for certain field offices which are insignificant on a quantitative basis. 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, 2011, we had approximately 365 full-time employees, none of whom were party to collective bargaining arrangements.

Regulatory Environment

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

Environmental and Land Use Regulation

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

California Environmental Quality Act ("CEQA"). CEQA is a California statute 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 several exploration wells that are part of our Monterey shale project in several counties in California. 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, hazardous substances, or other pollutants.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction sites, 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 were created or broadened pursuant to the Energy Policy Act of 2005.

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

Regulations imposed by the BOEMRE 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 BOEMRE 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, BOEMRE 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. See "—Remediation Plans and Procedures".

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 BOEMRE, the California State Lands Commission ("CSLC"), and other local agencies.

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

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to the federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes, although certain oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. The federal Environmental Protection Agency ("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 may therefore become 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 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. BOEMRE 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. 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. BOEMRE 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.

Marine Protected Areas ("MPAs"). In 2000, President Clinton issued Executive Order 13158, which directs federal agencies to strengthen management, protection and conservation of existing MPAs and to establish new MPAs. The executive order requires federal agencies to avoid causing harm to MPAs through federally conducted, approved, or funded activities. The order also directs EPA to propose new regulations under its Clean Water Act authority to ensure protection of the marine environment. This order and related Clean Water Act regulations have the potential to adversely affect our operations by restricting areas in which we may engage in future exploration, development, and production operations and by causing us to incur increased expenses.

Naturally Occurring Radioactive Materials ("NORM"). Our operations my generate wastes containing NORM. Certain oil and natural gas exploration and production activities can enhance the radioactivity of NORM. NORM primarily is regulated by state radiation control regulations. The Occupational Safety and Health Administration also has promulgated regulations addressing the handling and management of NORM. These regulations impose certain requirements regarding worker protection, the treatment, storage, and disposal of NORM waste, the management of NORM containers, tanks, and waste piles, and certain restrictions on the uses of land with NORM contamination.

Other Environmental Regulation. Our leases in federal waters on the Outer Continental Shelf are administered by the BOEMRE and require compliance with detailed BOEMRE regulations and orders. Under certain circumstances, BOEMRE 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 CSLC and DOGGR regulations. 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 protects an area of tidelands offshore Santa Barbara County that stretches west from Summerland Bay to Coal Oil Point, and includes waters offshore the unincorporated area of Montecito, the City of Santa Barbara and the University of California at Santa Barbara. It also protects 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 ("GHG") emissions that have been or 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. EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which established a statewide cap on GHGs designed to reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board adopted regulations that went into effect on January 1, 2012. These regulations are not expected to directly impact our operations as the first phase, beginning in 2012, includes all major industrial sources and utilities, while the second phase, which starts in 2015, will address distributors of transportation fuels, natural gas, and other fuels. We will continue to monitor the implementation of these regulations through industry trade groups and other organizations in which we are a member.

Other environmental protection statutes that may impact our operations include 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 BOEMRE 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 $92.5 million as of December 31, 2011. This figure reflects the expected future costs associated with site reclamation, facilities dismantlement and plugging and abandonment of wells. The discount rates used to calculate the present value varied depending on the estimated timing of the obligation, but typically ranged between 4% and 9%. Actual costs may differ from our estimates. Our financial statements do not reflect any liabilities relating to other environmental obligations.

Under a variety of applicable laws and regulations, including CERCLA, RCRA and BOEMRE 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. Certain of our facilities have known environmental contamination for which we will be responsible for the associated clean-up efforts, subject to our right to be indemnified by third parties in some cases. The regulators have generally not yet determined the applicable clean-up requirements associated with the facilities. However, we expect that we will be permitted to defer remedial actions until we cease operations at the relevant facilities. As the clean-up is expected to be performed at the end of the useful life of the relevant facilities, we have included estimates for the cost of the clean-up in our asset retirement obligations reflected in our financial statements.

Penalties for Non-Compliance. We believe that our operations are in material compliance with all applicable oil and natural gas, safety, environmental and land-use laws and regulations. However, from time to time we receive notices of noncompliance with Clean Air Act and other requirements from relevant regulatory agencies. We received a number of minor notices of violation ("NOVs") from regulatory agencies in 2011. We do not expect to incur significant penalties with respect to any outstanding NOV. See "Legal Proceedings."

Other Regulation

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

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

The rates, terms, and conditions applicable to the interstate and intrastate transportation of oil by pipelines is regulated by, respectively, the FERC under the Interstate Commerce Act and the California Public Utilities Commission under the California Public Resources Code.

The safety of our operations primarily is regulated by the BOEMRE, 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.

In August 2011, EPA proposed regulations specifically applicable to the oil and gas industry that would require operators to capture 95 percent VOC emissions from wells that are hydraulically fractured. The proposed regulations also would require reductions in emissions of methane and air toxics. The proposal includes four rules for the oil and natural gas industry: a new source performance standard for VOCs; a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. Any laws or regulations that may be adopted to restrict or reduce these emissions would likely require us to incur increased operating costs. The final rule is expected to be issued in March or April of 2012.

Executive Officers of the Registrant

The following table sets forth certain information with respect to our executive officers as of December 31, 2011.

Name	Age	Position
Timothy Marquez	53	Chairman and Chief Executive Officer
Edward O'Donnell	58	Chief Operating Officer
Timothy A. Ficker	44	Chief Financial Officer
Terry L. Anderson	64	General Counsel and Secretary
Mark DePuy	56	Senior Vice President, Business Development and Acquisitions

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.

Edward O'Donnell is our COO. Mr. O'Donnell initially joined us in 1997 as Vice President of development and was later Vice President of the Offshore Business Unit. From April 2001 to June 2002 he served as the President of our Domestic Division. From June 2002 through 2005 he provided independent business consulting to non-profit organizations and small retail businesses. In 2006 he became the CEO of Gong Zhu Enterprises, a provider of financial, accounting, and management consulting services to small retail businesses. Mr. O'Donnell also served two terms on our board of directors. He re-joined us in March 2007 as Senior Vice President and was appointed COO in January 2012. In addition, on January 18, 2012 we announced a succession plan whereby Mr. Marquez plans to step down as our CEO in the third quarter of 2012, and, at that time, Mr. O'Donnell is expected to assume the role of CEO. Mr. O'Donnell has 20 years of experience with Unocal Corporation in various engineering and management positions. He holds a B.S. degree in petroleum engineering from Montana Tech, an M.S. in petroleum engineering from the University of Southern California and an M.B.A. from Pepperdine University.

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

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

Mark DePuy is our Senior Vice President, Business Development and Acquisitions. Mr. DePuy initially joined us in 2005 as Vice President of Northern Assets. The following year, he was named

COO and oversaw our assets in Northern and Southern California, as well as numerous field operations in Texas. Mr. DePuy resigned as our COO in October 2008, after which he provided consulting services for us on coastal development projects in California. From March 2010 through November 2011, he served as CEO and President of Great Western Oil and Gas, a private oil and gas company with operations focused primarily in Colorado and North Dakota. Mr. DePuy re-joined us in his current role in December 2011. He has 27 years of experience in various operational, management and business planning functions with Unocal/Chevron in both the domestic and international operations. He has an M.B.A. from the University of California, Los Angeles and a B.S. in petroleum engineering from the Colorado School of Mines.

Available Information

We maintain a link to investor relations information on our website, *www.venocoinc.com*, where we make available, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, or Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We also make available on our website copies of the charters of the audit, compensation and corporate governance/nominating committees of our board of directors, our code of business conduct and ethics and our corporate governance guidelines. Stockholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Corporate Secretary, Venoco, Inc., 370 17th Street, Suite 3900, Denver, Colorado, 80202-1370. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at *www.sec.gov* that contains the documents we file with the SEC. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included as an inactive textual reference only.

ITEM 1A. Risk Factors

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

Declines in the prices we receive for our oil and natural gas production adversely affect many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. For example, due in significant part to lower commodities prices, our revenues from oil and natural gas sales and cash flow from operations declined 52% and 44%, respectively, in 2009 compared to 2008. Declines in the prices we receive for our oil and natural gas also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. For example, continued depressed natural gas prices have caused us to reduce our drilling activity in the Sacramento Basin from 93 wells spud in 2010 to 40 wells in 2011 and we have included five wells in our 2012 capital expenditure budget. In addition, declines in prices reduce the amount of oil and natural gas that we can produce economically and, as a result, adversely affect our quantities of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our revolving credit facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities of those reserves.

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

In addition to factors affecting the price of oil and natural gas generally, the prices we receive for our oil and natural gas production is affected by factors specific to us and to the local markets where the production occurs. Pricing can be influenced by, among other things, local or regional supply and demand factors (such as refinery or pipeline capacity issues, trade restrictions and governmental regulations) and the terms of our sales contracts.

The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. For example, our California oil typically has a lower gravity, and a portion has higher sulfur content, than oil sold at certain benchmark prices. Therefore, because our oil requires more complex refining equipment to convert it into high value products, it may sell at a discount to those prices. This discount, or differential, varies over time and can be affected by factors that do not have the same impact on the price of premium grade light oil. We cannot predict how the differential applicable to our production will change in the future, and it is possible that it will increase. The difficulty involved in predicting the differential also makes it more difficult for us to effectively hedge our production. Many of our hedging arrangements are based on benchmark prices and therefore do not fully protect us from adverse changes in the differential applicable to our production.

Our planned operations will require additional capital that may not be available.

Our business is capital intensive, and requires substantial expenditures to maintain currently producing wells, to make the acquisitions and/or conduct the exploration, exploitation and development activities necessary to replace our reserves, to pay expenses and to satisfy our other obligations. In recent years, we have chosen to pursue projects that required capital expenditures in excess of cash flow from operations. That fact has made us dependent on external financing to a greater degree than many of our competitors. Our substantial existing indebtedness increases the risk that external financing will not be available to us when needed. If we reduce our capital spending in an effort to conserve cash, this would likely result in production being lower than anticipated, and could result in reduced revenues, cash flow from operations and income.

It may be difficult or impossible for us to finance our operations through the incurrence of additional indebtedness.

We have relied on borrowings under our revolving credit facility to finance our operations in some recent periods. Lenders may not fund borrowings under the facility when we request them to do so. In 2009, a former lender under the facility, Lehman Commercial Paper, Inc., ceased funding amounts under the facility as a result of the bankruptcy of its parent company, Lehman Brothers Holdings Inc. Existing lenders under the revolving credit facility may face similar issues. Our ability to borrow under the facility may also be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the facility. It may be difficult to maintain compliance with the maximum debt to EBITDA (as defined in the agreement) ratio in the future if we borrow a significant portion of the available capacity under the facility and/or our EBITDA is adversely affected by operational problems, counterparties' failure to perform under hedge agreements or other factors. In addition, the borrowing base under the facility is subject to redetermination periodically and from time to time in the lenders' discretion. Borrowing base reductions may occur with respect to the revolving credit facility as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. Due in significant part to lower commodity prices, the borrowing base under the revolving credit facility was reduced in early 2009 from $200 million to $125 million. Our current borrowing base is $200 million. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time.

Sources of external debt financing other than revolving credit facility borrowings may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Our ability to incur additional indebtedness will be limited under the terms of the revolving credit facility, the indenture governing our 8.875% senior notes and the indenture governing our 11.50% senior notes, which we refer to collectively as our debt agreements (see—"Liquidity and Capital Resources—Capital Resources and Requirements"). In addition, if we finance our operations through borrowings under our revolving credit facility or other additional indebtedness, the risks that we now face relating to our current debt level would intensify, and it may be more difficult to satisfy our existing financial obligations.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness. At February 14, 2012, we had total outstanding debt of $679.0 million, comprised of $35.0 million outstanding on our revolving credit facility, $500.0 million under our 8.875% senior notes and $144.0 million (net of discount) under our 11.50% senior notes. Interest obligations on our indebtedness are significant. Our debt bears interest at a weighted average interest rate of approximately 9.20% as of February 14, 2012. In 2011, we had interest expense of $61.1 million.

Our level of indebtedness could have important effects on our business. For example, it could:

- make it more difficult for us to satisfy our obligations under our debt agreements and increase the risk that we may default on our debt obligations;
- require us to dedicate a substantial portion of our cash flow from operations and certain types of transactions to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisition and other investment opportunities and other general business activities;
- limit our flexibility in planning for, or reacting to, changes in commodity prices, our business or the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds on favorable terms or at all;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in our debt agreements which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

If our cash flow and other capital resources are insufficient to fund our obligations under our debt agreements on a current basis and at maturity, we could attempt to refinance or restructure the debt or to repay the debt with the proceeds from an equity offering or from sales of assets. The proceeds of future borrowings, equity financings or asset sales may not be sufficient to refinance or repay the debt, and we may be unable to complete such transactions in a timely manner, on favorable terms, or at all. In addition, our debt agreements contain provisions that would limit our flexibility in responding to a shortfall in our expected liquidity by selling assets or taking certain other actions. For example, we could be required to use some or all of the proceeds of an asset sale to reduce amounts outstanding under our debt agreements in some circumstances. Any refinancing that requires the use of cash could require us to reduce or delay planned capital expenditures. There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

We also face a refinancing risk. Significant amounts of our indebtedness do not require current payments of principal, but are payable in full on maturity. Cash flow from operations may not be sufficient to repay the outstanding balance on our debt when it matures. Global capital markets have experienced a severe contraction in the availability of debt financing in the recent past. Financial effects of this crisis were exacerbated in the oil and natural gas industry by the effect of volatile commodity prices. The ability to pay principal and interest on our debt, and to refinance our debt upon maturity, will depend not only upon our financial and operating performance, but on the state of the global economy, credit markets and commodity prices during the period through the time of refinancing, many of which are factors over which we have no control. There can be no assurances that we will be able to make principal and interest payments on our indebtedness and to refinance our indebtedness at maturity as needed.

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

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

Additionally, SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be recorded if they relate to wells scheduled to be drilled within five years after the date of booking. This recently-implemented rule has limited and may continue to limit our potential to record additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

At December 31, 2011, 49% of our estimated proved reserves were proved undeveloped and 10% were proved developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells as contrasted with the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenues from estimated proved developed non-producing reserves will not be realized until some time in the future, if at all.

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

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

Exploration, exploitation and development activities are subject to many risks. For example, new wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. Similarly, previously producing wells that are returned to production after a period of being shut in may not produce at levels that justify the expenditures made to bring the wells back on line. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. In addition, the cost of exploration, exploitation and development activities is subject to numerous uncertainties, and cost factors can adversely affect the economics of a project. Further, our exploration, exploitation and 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;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- compliance with environmental and other governmental requirements, including with respect to permitting issues; and
- costs of, or shortages or delays in the availability of, drilling rigs, equipment, qualified personnel and services.

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

Drilling results in emerging plays, such as the onshore Monterey shale, are subject to heightened risks.

Part of our strategy is to pursue acquisition, exploration and development activities in emerging plays such as our onshore Monterey shale project. Our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Because emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. In addition, part of our drilling strategy to maximize recoveries from the onshore Monterey shale formation may involve drilling and/or completion techniques that have proven to be successful in other shale formations. These drilling and completion strategies and techniques require greater amounts of capital investment than more established plays. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established. If drilling success rates or production are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations or other operational problems, the value of our position in the affected area will decline, our results of operations, financial condition and liquidity will be adversely impacted and we could incur material write-downs of unevaluated properties.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not control. When these facilities or systems 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 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.

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

To reduce our exposure to fluctuations in the prices of oil and natural gas, we enter into hedging arrangements with respect to a substantial portion of our oil and natural gas production. See

"Quantitative and Qualitative Disclosures About Market Risk" for a summary of our hedging activity. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

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

A significant percentage of our cash flow in some prior periods resulted from payments made to us by our hedge counterparties. If hedge counterparties are unable to make payments to us under our hedging arrangements, our results of operation, financial condition and liquidity would be adversely affected. In addition, the uncertainties associated with our hedging programs are greater than those of many of our competitors because the price of the heavy oil that we produce in California is subject to risks that are in addition to the price risk associated with premium grade light oil. Also, our working capital could be impacted if we enter into derivative arrangements that require cash collateral and commodity prices subsequently change in a manner adverse to us. The obligation to post cash or other collateral could, if imposed, adversely affect our liquidity.

Moreover, we have experienced, and may continue to experience, substantial realized and unrealized losses relating to our hedging arrangements. Realized commodity derivative gains or losses represent the difference between the strike prices set forth in hedging contracts settled during the relevant period and the ultimate settlement prices. We incur a realized commodity derivative loss when a contract is settled at a price above the strike price. Losses of this type reflect the limit our hedging arrangements impose on the benefits we would otherwise have received from an increase in the price of oil or natural gas during the period. Unrealized commodity derivative gains and losses represent the change in the fair value of our open derivative contracts from period to period. We incur an unrealized commodity derivative loss when the futures price used to estimate the fair value of a contract at the end of the period rises. Increases in oil prices have caused us to incur substantial realized and unrealized commodity derivative losses in some recent periods, and we may experience similar or greater losses of these types in future periods. We may experience more volatility in our commodity derivative gains and losses than many of our competitors because we do not designate our derivatives as cash flow hedges for accounting purposes and because we hedge a larger percentage of our production than some of our competitors.

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

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to exploration for, and the exploitation, development, production and transportation of, oil and natural gas, as well as environmental, safety and other matters. Existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations, may harm our business, results of operations and financial condition. Laws and regulations applicable to us include those relating to:

- land use restrictions, which are particularly strict along the coast of southern California where many of our operations are located;
- drilling bonds and other financial responsibility requirements;
- spacing of wells;
- emissions into the air (including emissions from ships in the Santa Barbara channel);
- unitization and pooling of properties;
- habitat and endangered species protection, reclamation and remediation;

- the containment and disposal of hazardous substances, oil field waste and other waste materials;
- the use of underground storage tanks;
- transportation and drilling permits;
- the use of underground injection wells, which affects the disposal of water from our wells;
- safety precautions;
- the prevention of oil spills;
- the closure of production facilities;
- operational reporting; and
- taxation and royalties.

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

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

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities, including suspension or termination of operations. 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." These suits and/or related indemnity claims could have a material adverse effect on our financial condition. Moreover, 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, including, in some circumstances, operators of properties in which we have an interest and parties that provide transportation services for us. Similarly, some environmental laws and regulations impose joint and several liability, meaning that we could be held responsible for more than our share of a particular reclamation or other obligation, and potentially the entire obligation, where other parties were involved in the activity giving rise to the liability. In addition, we may be required to make large and unanticipated capital expenditures to comply with applicable laws and regulations, for example by installing and maintaining pollution control devices. Similarly, our plugging and abandonment obligations will be substantial and may be more than our estimates. Compliance costs are relatively high for us because many of our properties are located offshore California and in other environmentally sensitive areas and because California environmental laws and regulations are generally very strict. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters, but they will be material. Environmental risks are generally not fully insurable.

Similarly, our operations could be adversely affected by environmental and other laws and regulations that require us to obtain permits before commencing drilling or other activities. For example, we recently terminated our pursuit of a proposed lease extension in the South Ellwood field due to difficulties in obtaining the necessary permits. In addition, even when permits are granted, they may be subject to conditions which impose delays on a project, increase its costs or reduce its benefits to us. Permitting and similar risks are high for us relative to many of our competitors because oil and natural gas projects are frequently the source of considerable political controversy in California, and political opposition may make it more difficult for us to obtain consents and approvals for our projects.

Changes in applicable laws and regulations could increase our costs, reduce demand for our production, impede our ability to conduct operations or have other adverse effects on our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, the EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other greenhouse gas ("GHG") present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which established a statewide cap on GHGs designed to reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board adopted regulations that went into effect on January 1, 2012. These regulations are not expected to directly impact our operations as the first phase, beginning in 2012, includes all major industrial sources and utilities, while the second phase, which starts in 2015, will address distributors of transportation fuels, natural gas, and other fuels. We will continue to monitor the implementation of these regulations through industry trade groups and other organizations in which we are a member. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Reform Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through implementing regulations to be adopted by the SEC, the Commodities Futures Trading Commission and other regulators. We are currently assessing the likely impact of the Reform Act on our operations, and this assessment will continue as the regulatory process contemplated by the Reform Act progresses. If, as a result of the Reform Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy or to meet the hedging requirements contained in our revolving credit facility. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy. We are more vulnerable to the adverse consequences of changes in laws and regulations relating to derivatives than many of our competitors because we hedge a relatively large proportion of our expected production and because our hedging strategy is integral to our overall business strategy.

Following the Deepwater Horizon well blowout in the Gulf of Mexico, the Secretary of the U.S. Department of Interior imposed a drilling moratorium in May 2010, which delayed a planned redrill of an inactive well from Platform Gail. That moratorium was subsequently lifted for fixed-leg platforms like Platform Gail. However, additional moratoria, or similar rules promulgated by other governmental authorities, could have significant impacts on our operations in the future. In addition, the U.S. Department of Interior has experienced significant delays in processing permit applications for new drilling projects. Delays in the government's permitting process could have significant impacts on the industry as a whole and our future results of operations.

In addition, some of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation. The EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act's Underground Injection Control Program and has commenced drafting guidance for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced in October 2011 that it is also commencing a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the U.S. Department of Energy, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior is also considering regulation of hydraulic fracturing activities on public lands. In addition, legislation called the Fracturing Responsibility and Awareness of Chemicals Act has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances. These proposals, to the extent adopted, may increase our costs and make it more difficult, or impossible, to pursue some of our exploration or development projects.

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

President Obama's 2013 Fiscal Year Budget includes proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy. We do not have insurance to cover all of the risks that we may face.

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

- well blowouts;

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

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

In addition to lost production and increased costs, these hazards could cause serious injuries, fatalities, contamination or property damage for which we could be held responsible. The potential consequences of these hazards are particularly severe for us because a significant portion of our operations are conducted offshore and in other environmentally sensitive areas, including areas with significant residential populations. We do not maintain insurance in amounts that cover all of the losses to which we may be subject, and the insurance we have may not continue to be available on acceptable terms. Moreover, some risks we face are not insurable. Also, we could in some circumstances have liability for actions taken by third parties over which we have no or limited control, including operators of properties in which we have an interest. The occurrence of an uninsured or underinsured loss could result in significant costs that could have a material adverse effect on our financial condition and liquidity. In addition, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed.

A failure to complete successful acquisitions would limit our growth.

Because our oil and natural gas properties are depleting assets, our future oil and natural gas reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Acquiring additional oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise is an important component of our strategy. 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 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. When we acquire properties on an "as-is" basis, we have limited or no remedies against the seller with respect to these types of problems.

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

Enhanced recovery techniques may not be successful, which could adversely affect our financial condition or results of operations.

Certain of our properties may provide opportunities for a CO_2 enhanced recovery project. Risks associated with enhanced recovery techniques include, but are not limited to, the following:

- geologic unsuitability of the properties subject to the enhanced recovery project;
- unavailability of an economic and reliable supply of CO_2, or other shortages of equipment;
- lower than expected production;
- longer response times;
- higher operating and capital costs; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect the results of the affected project, our financial condition and our results of operations. We may pursue other enhanced recovery activities from time to time as well, and those activities may be subject to the same or similar risks.

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. These events, many of which are beyond our control, could have a material adverse effect on our results of operations and financial condition and could reduce estimates of our proved reserves.

The loss of our key personnel could adversely affect our business.

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

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

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

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

Other companies operated approximately 4% of our production in the fourth quarter of 2011. Our ability to exercise influence over operations for these properties and their associated costs is limited. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to exploration, exploitation, development or acquisition activities. The success and timing of exploration, exploitation and development activities on properties operated by others depend upon a number of factors that may be outside our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;

- approval of other participants in drilling wells; and
- selection of technology.

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

Changes in the financial condition of any of our large oil and natural gas purchasers or other significant counterparties could adversely affect our results of operations and liquidity.

For the year ended December 31, 2011, approximately 95% of our oil and natural gas revenues were generated from sales to four purchasers: ConocoPhillips, Enserco Energy, Calpine Producer Services LP and Concord Energy LLC. In 2012, we expect to sell a significant amount of our production to Tesoro Refining and Marketing Company. A material adverse change in the financial condition of any of our largest purchasers could adversely impact our future revenues and our ability to collect current accounts receivable from such purchasers. We face similar counterparty risks in connection with other contracts under which we may be entitled to receive cash payments, including insurance policies and commodity derivative agreements. Major counterparties may also seek price or other concessions from us if they perceive us to be dependent on them or to lack viable alternatives.

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

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

All of our producing properties are located in one state and adverse developments in that state would negatively affect our financial condition and results of operations.

All of our principal properties are located in California. Our Southern California and Sacramento Basin properties represented approximately 53% and 47%, respectively, of our proved reserves as of December 31, 2011 and accounted for a combined 100% of our 2011 production. Any circumstance or event that negatively impacts the production or marketing of oil and natural gas in California generally, or in Southern California or the Sacramento Basin in particular, would adversely affect our results of operations and cash flows. Many of our competitors have operations that are more geographically dispersed than ours, and therefore may be less subject than we are to risks affecting a particular geographic area.

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 50.3% of our outstanding common stock as of February 14, 2012. 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 generally has the direct or indirect power to:

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

Mr. Marquez's significant ownership interest could adversely affect investors' perceptions of our corporate governance. In addition, Mr. Marquez may have an interest in pursuing acquisitions, divestitures and other transactions that involve risks to us. For example, Mr. Marquez could cause us to make acquisitions that increase our indebtedness or to sell revenue generating assets. Mr. Marquez may from time to time acquire and hold interests in businesses that compete directly or indirectly with us. Also, we have engaged, and may continue to engage, in related party transactions involving Mr. Marquez. For example, we have entered into a non-exclusive aircraft sublease agreement with TimBer, LLC, a company owned by Mr. Marquez and his wife.

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

Sales of a substantial number of shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional common or preferred stock. As of February 14, 2012, Timothy Marquez beneficially owned approximately 50.3% of our common stock, primarily through the Marquez Trust. As of December 31, 2011, we had granted options to purchase an aggregate of approximately 0.8 million shares of our common stock and 2.8 million shares of restricted stock to certain of our directors and employees. The Marquez Trust and these other holders, subject to compliance with applicable securities laws and vesting requirements, are permitted to sell shares they own or acquire upon the exercise of options in the public market. Sales of a substantial number of shares of our common stock by those holders could cause our stock price to fall.

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

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

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

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

These provisions could discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders, adversely affect the voting power of holders of common stock and limit the price that investors might be willing to pay in the future for shares of our common stock. Similarly, our debt agreements have provisions relating to a change of control of our company that could have a similar effect.

There can be no assurance that the transaction contemplated by the merger agreement between us and Mr. Marquez and certain of his affiliates will be completed. If the merger is not completed, the market price of our common stock may be adversely affected.

In August 2011, our board of directors received the proposal from Mr. Marquez described in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview—Recent Events." In January 2012, we announced that we entered into a definitive merger agreement with Mr. Marquez and certain of his affiliates pursuant to which he will acquire all shares of which he is not the beneficial owner for $12.50 per share in cash. The closing trading price of our common stock was $8.98 per share on the last trading day prior to the announcement of the proposal, and it was $7.69 per share on the last trading day prior to the announcement of the merger agreement. After each announcement, the trading price of our common stock increased and traded closer to the $12.50 per share proposal price. However, the trading price of our common stock has been subject to significant volatility since the original announcement. Completion of the transaction is subject to certain closing conditions, including procurement of financing, receipt of shareholder approval (including approval by a majority of the unaffiliated shareholders) and other customary conditions. There can be no assurance that those conditions will be satisfied. If the transaction is not consummated, the stock price could fall below its current trading range. In addition, we could be required to make an expense reimbursement payment to an affiliate of Mr. Marquez if the merger agreement is terminated in certain circumstances. We could also be adversely affected by litigation that has been initiated in connection with the transaction.

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 Venoco. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in 2012. We vigorously defended the actions, and will continue to do so until they are resolved. Certain defendants and related parties have made claims for indemnity which we are disputing. We cannot predict the cost of 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. If the insurer ceases to provide such defense 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 its policies applies, we will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

Based on the information known to us to date, we do not believe that it is probable that a material judgment against us will result. Therefore, no liability has been accrued. If one or more of these matters are resolved in a manner adverse to us, and if insurance coverage is determined not to be applicable, their impact on our results of operations, financial position and/or liquidity could be material.

State Lands Commission Royalty Litigation

In November 2011, the California State Lands Commission (SLC) filed suit against us in Santa Barbara County alleging that we underpaid royalties on oil and gas produced from the South Ellwood field in California for the period from August 1, 1997 through May 2011 by approximately $9.5 million. The case has since been removed to Los Angeles County, California. The principal issues in dispute are (i) the oil price on which royalties should be calculated and (ii) whether we are entitled to deduct the cost of transporting oil from the South Ellwood field to the point of sale in calculating the royalty. With respect to the oil price, we have paid royalties based on the price we actually received in arms-length transactions. The SLC contends that we should be paying royalties based on the higher of the price actually received and the highest "posted price" for oil sold in the Midway Sunset Field, near Bakersfield, California. With respect to the deduction of transportation costs, we believe that state law allows us to adjust the sale price to reflect the cost of delivering the oil from the field to the point of sale. Based on our review of the SLC's contentions, audit records and additional historical records, we believe that we may have overpaid royalties on oil and gas production during the period in question and we may be owed a refund of such overpayments. We believe the position of the SLC is without merit and we intend to vigorously contest the suit and to enforce our right to receive a refund of royalties we may have overpaid. We do not believe that it is probable that a material judgment against us will result. Therefore, no liability has been accrued.

Delaware Litigation

On August 26, 2011, Timothy Marquez, our Chairman and CEO, submitted a nonbinding proposal to our board of directors to acquire all of the shares of Venoco he does not beneficially own for $12.50 per share in cash (the "Marquez Proposal"). As a result of that proposal, four lawsuits were filed in the Delaware Court of Chancery in 2011 against the Company and each of our directors by shareholders alleging that the Company and our directors had breached their fiduciary duties to the shareholders in connection with the Marquez Proposal. A fifth lawsuit filed in 2011, also in the Delaware Court of Chancery, named only Mr. Marquez as a defendant. On January 16, 2012, we announced we had entered into a merger agreement with Mr. Marquez and certain of his affiliates pursuant to which, at closing, each of the shareholders other than Mr. Marquez and his affiliates would receive $12.50 for each share of Company stock (the "Merger"). Following announcement of the merger agreement, three additional suits were filed in Delaware and three suits were filed in federal court in Colorado naming as defendants the Company and each of our directors. Each action seeks certification as a class action. Plaintiffs in both the Delaware and Colorado actions challenge the Merger and allege, among other things, that the consideration to be paid is inadequate. The complaints seek, among other relief, to enjoin defendants from consummating the Merger and to direct defendants to exercise their fiduciary duties to obtain a transaction that is in the best interests of the shareholders. We have reviewed the allegations contained in the complaints and believe they are without merit.

Other—In addition, we are a party from time to time to other claims and legal actions that arise in the ordinary course of business. We believe that the ultimate impact, if any, with respect to these other claims and legal actions will not have a material effect on our consolidated financial position, results of operations or liquidity.

ITEM 4. Mine Safety Disclosures.

Not applicable.

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PART II

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

Price Range of Common Stock and Number of Holders

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

The following table sets forth the high and the low sale prices per share of our common stock for the periods indicated. The closing price of the common stock on February 14, 2012 was $11.11.

	2010		2011	
Period	High	Low	High	Low
1st Quarter	$14.40	$11.29	$22.22	$15.93
2nd Quarter	$18.50	$12.20	$18.59	$12.20
3rd Quarter	$21.07	$15.63	$14.75	$ 8.42
4th Quarter	$20.55	$14.97	$10.82	$ 6.56

As of February 14, 2012, there were 361 record holders of our common stock.

Unregistered Sales of Equity Securities

Not applicable.

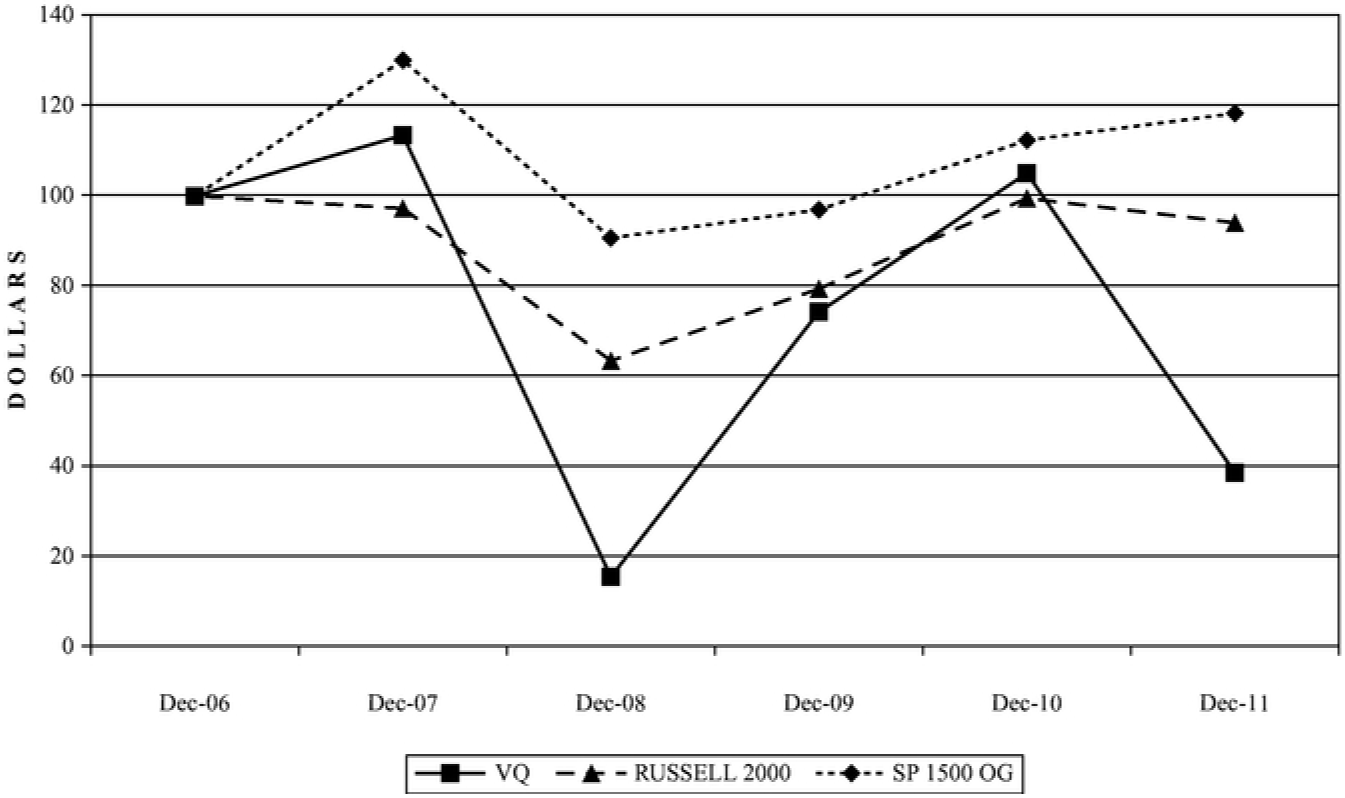
Dividend Policy

We have not declared any cash dividends on our common stock during the two most recent fiscal years and have no plans to do so in the foreseeable future. The ability of our board of directors to declare any dividend is subject to limits imposed by the terms of our debt agreements, which currently prohibit us from paying dividends on our common stock. 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, 2011, 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 purposes only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

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



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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. No pro forma adjustments have been made for the acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below. Amounts are in thousands, except per share data.

	Years ended December 31,				
	2007	2008	2009	2010	2011
	(in thousands, except per share data)				
Statement of Operations Data:					
Oil and natural gas sales	$ 371,450	$ 554,270	$ 267,163	$ 290,608	$ 323,423
Other	3,355	3,603	3,331	4,684	5,355
Total revenues	374,805	557,873	270,494	295,292	328,778
Lease operating expense	107,295	133,773	95,213	84,255	94,100
Production and property taxes	12,026	15,731	10,128	6,701	6,376
Transportation expense	4,356	4,311	3,163	9,102	9,348
Depletion, depreciation and amortization	98,814	134,483	86,226	78,504	85,817
Impairment of oil and natural gas properties	—	641,000	—	—	—
Accretion of asset retirement obligations	3,914	4,203	5,765	6,241	6,423
General and administrative, net of amounts capitalized	31,770	43,101	36,939	37,554	39,186
Total expenses	258,175	976,602	237,434	222,357	241,250
Income (loss) from operations	116,630	(418,729)	33,060	72,935	87,528
Interest expense, net	60,115	54,049	40,984	40,584	61,113
Amortization of deferred loan costs	4,197	3,344	2,862	2,362	2,310
Interest rate derivative losses (gains), net	17,177	20,567	16,676	31,818	1,083
Loss on extinguishment of debt	12,063	—	8,493	—	1,357
Commodity derivative losses (gains), net	142,650	(116,757)	25,743	(68,049)	(40,649)
Total financing costs and other	236,202	(38,797)	94,758	6,715	25,214
Income (loss) before income taxes	(119,572)	(379,932)	(61,698)	66,220	62,314
Income tax provision (benefit)	(46,200)	11,200	(14,400)	(1,300)	—
Net income (loss)	$ (73,372)	$ (391,132)	$ (47,298)	$ 67,520	$ 62,314
Earnings per common share:					
Basic	$ (1.58)	$ (7.75)	$ (0.93)	$ 1.23	$ 1.02
Diluted	$ (1.58)	$ (7.75)	$ (0.93)	$ 1.21	$ 1.02
Cash Flow Data:					
Cash provided (used) by:					
Operating activities	$ 160,863	$ 212,379	$ 118,691	$ 160,673	$ 125,496
Investing activities	(433,363)	(332,861)	(1,953)	(108,296)	(246,481)
Financing activities	273,871	110,938	(116,510)	(47,772)	124,126
Other Financial Data:					
Capital expenditures	$ 322,283	$ 318,582	$ 176,812	$ 211,621	$ 246,228
Balance Sheet Data (end of period):					
Cash and cash equivalents	$ 9,735	$ 191	$ 419	$ 5,024	$ 8,165
Property, plant and equipment, net	1,131,032	702,734	619,430	648,044	810,465
Total assets	1,265,485	864,254	739,543	750,923	929,744
Long-term debt, excluding current portion	691,896	797,670	695,029	633,592	686,958
Total stockholders' equity (deficit)	245,602	(135,167)	(174,496)	(84,237)	73,028

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. As used in this report, unless the context otherwise indicates, references to "we," "our," "ours," and "us" refer to Venoco, Inc. and its subsidiaries collectively.

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 have the potential to add significant reserves on a cost-effective basis and through selective acquisitions of underdeveloped properties. In recent years, the exploration, exploitation and development of the onshore Monterey shale formation has taken a fundamental role in our corporate strategy, and efforts to expand our knowledge of the onshore formation have increased significantly. A substantial portion of our production is from offshore wells targeting the fractured Monterey shale formation, and we believe that there are significant opportunities relating to the Monterey shale formation onshore as well.

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

Recent Events

In August 2011, our board of directors received a proposal from our Chairman and CEO, Timothy Marquez, to acquire all of the outstanding shares of our common stock of which he is not the beneficial owner for $12.50 per share in cash (the "Marquez Proposal"). Mr. Marquez is currently the beneficial owner of approximately 50.3% of the common stock. The board of directors formed a special committee comprised of all independent directors to evaluate and consider this proposal as well as third party alternatives. In January 2012, we announced that we had entered into a definitive merger agreement with Mr. Marquez and certain of his affiliates pursuant to which he will acquire all shares he does not beneficially own for $12.50 per share in cash. The special committee also announced that it unanimously concluded that the transaction with Mr. Marquez was in the best interest of the Company's minority shareholders. As a result, the agreement was approved by the full board of directors, with Mr. Marquez abstaining. Completion of the transaction is subject to certain closing conditions, including procurement of financing, receipt of shareholder approval (including approval by a majority of unaffiliated shareholders) and other customary conditions. As the transaction remains subject to certain closing conditions, there can be no assurance that this transaction will be consummated. See the "Risk Factors" section of this Annual Report.

Capital Expenditures

We have developed an active capital expenditure program to take advantage of our extensive inventory of drilling prospects and other projects. Our development, exploitation and exploration capital expenditures were $255 million in 2011, up from $218 million in 2010. Approximately $185 million of the 2011 capital expenditures went to drilling and rework activities, $20 million to facilities, and the remaining $50 million to land, seismic and capitalized G&A costs. We incurred approximately $180 million or 71% of our 2011 capital expenditures in Southern California and $74 million or 29% in the Sacramento Basin with the remainder going toward exploration projects. Of the total amount spent in Southern California, approximately $113 million went to projects targeting the onshore Monterey shale formation.

Our 2012 development, exploitation and exploration capital expenditure budget is $255 million, of which approximately $223 million or 87% is expected to be deployed in Southern California and $32 million or 13% in the Sacramento Basin. Of the $223 million allocated to Southern California, approximately $100 million is expected to be deployed to onshore Monterey shale activities with the remainder going to activities at legacy Southern California fields. The aggregate levels of capital expenditures for 2012, and the allocation of those expenditures, are dependent on a variety of factors, including the availability of capital resources to fund the expenditures and changes in our business assessments as to where our capital can be most profitably employed. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from our estimates. The following summarizes certain significant aspects of our 2011 capital spending program and the outlook for 2012.

Southern California—Legacy Fields

In the West Montalvo field, we have pursued an active workover, recompletion and return to production program that has resulted in significant production gains since we acquired the field in May 2007. The field has not been fully delineated offshore or fully developed onshore and we continue to evaluate our drilling results and refine our development program for the coming years. During 2011, we spud five wells, one onshore and four offshore. We also performed five recompletions during the year. Our 2012 capital expenditure budget includes plans to drill seven wells, one of which was spud in the fourth quarter and completed during the first quarter of 2012. We spud two additional wells in the first quarter of 2012 and plan to spud a third well later in the quarter.

In the Sockeye field, we redrilled two inactive wells that target the Monterey shale formation during 2011. Our 2012 capital expenditure budget includes plans to drill three wells at Sockeye, which are expected to be drilled in the first half of the year.

At the South Ellwood field, we have received permits to drill two undeveloped locations and continue to work on permitting two additional locations on our existing leases. We have completed the facilities work necessary to begin drilling those locations and plan to spud the first well in March. Our 2012 capital expenditure budget includes plans to drill four wells in the field during 2012.

In addition, during the third quarter of 2011 our subsidiary Ellwood Pipeline, Inc. received the approvals necessary to begin construction of a common carrier pipeline that allows us to transport our oil from the field to refiners without the use of a barge or the marine terminal we previously used. The pipeline commenced operations during January 2012. Primarily as a result of the pipeline approval, the estimated reserve life of the South Ellwood field was extended by approximately 30 years and proved reserves in the field increased by approximately 8.1 MMBOE, based on SEC pricing as of December 31, 2011.

Southern California—Onshore Monterey Shale

In 2006, we began actively leasing onshore acreage in Southern California targeting the Monterey shale. Our leasing has focused on areas where we believe the Monterey shale will produce light, sweet oil, and where the quality and depth of the Monterey shale is expected to be advantageous. To date, our onshore Monterey shale acreage position totals approximately 256,000 gross and 170,000 net acres and is located primarily in three basins: Santa Maria, Salinas Valley and San Joaquin. We also have an additional 60,000 gross and 46,000 net acres with Monterey shale production or potential which are held by production at our legacy Southern California fields.

During 2011 we spud 12 onshore wells targeting the Monterey shale, including three horizontal wells, and set casing on 13 wells (including wells spud in 2010). In total, since the beginning of 2010 when we began actively drilling wells targeting the onshore Monterey shale formation through 2011, we have spud 24 wells (17 vertical and seven horizontal), of which 20 have had casing set and two wells, both vertical, were used as pilot holes for two horizontal wells. In addition, earlier this year, we completed the second and final phase of a 3-D seismic shoot in the San Joaquin area which covered approximately 500 square miles. We continue to analyze the data from the shoot.

We have been encouraged by the scientific information collected thus far, particularly in two of our prospect areas (the Sevier field in the San Joaquin Basin and the South Salinas field in the Salinas Valley). To date, we have not seen material levels of production or reserves from the program. We believe we will see production resulting from our delineation drilling and testing efforts which began at Sevier in 2011 and which will continue into 2012. During 2011 we spud six vertical wells (including four wells during the fourth quarter) at Sevier. Due to terrain and public lands issues, we drill from pads that are large enough to drill multiple wells. At times, however, in order to drill another new well, we need to shut in testing of other wells on the same drill pad. Because of this, and because we have several intervals to test independently in each well, we do not have longer term tests by interval or by well. However, we have been encouraged by the testing and geologic data we have obtained from each subsequent well.

Our 2012 capital expenditure budget includes plans to drill 15 to 20 wells at Sevier, where we currently have one rig operating. Additionally, we plan to study our onshore Monterey wells drilled in 2010 and 2011 for recompletion opportunities based on knowledge we have gained over the past few years. We also plan to collect 3D seismic data at Sevier and Salinas Valley during 2012.

Sacramento Basin

In the Sacramento Basin, we continue to pursue our infill drilling program in the greater Grimes and Willows fields. During 2011, we spud 40 wells and performed 237 recompletions in the basin. We continue to test and evaluate potential downspacing opportunities in the basin as well as new methods of improving productivity and reducing drilling costs. We also continue to pursue our hydraulic fracturing program in the basin with 21 wells fractured during 2011.

As of December 31, 2011, we had identified 734 drilling locations in the basin, and we anticipate identifying additional locations as we pursue further exploration, exploitation and development opportunities. We believe the Sacramento Basin presents significant exploration opportunities and in order to further our understanding of these opportunities we drill a small number of what we consider to be exploratory wells in the basin each year. In early 2011 we drilled a discovery well on an anomaly which we identified using 3D seismic data we acquired with leasehold in 2009. The discovery well's average net production in 2011 was 2.3 million cubic feet per day and it extended the boundaries of the Grimes field. We drilled additional wells in 2011 along this extension area and these wells, combined with the discovery well, exited the year at a net production rate of 8.3 million cubic feet per day. Operationally, we distinguish these exploratory wells from the numerous non-proved locations that we drill each year as part of our development drilling program but are considered "exploratory wells" as defined in SEC Regulation S-X.

We have reduced our activity levels in the basin in recent years as a result of depressed natural gas prices and our increased focus on our oil-based projects including Monterey shale activities. Our 2012 capital expenditure budget contemplates a continuation of this strategy. We plan to drill five wells and perform 180 recompletions and seven fracs. We anticipate the activity levels contemplated in our 2012 budget will result in average daily production which is lower than 2011 average daily production. We would expect to return to a focus on growth in the basin when natural gas prices improve. As of December 31, 2011, our acreage position in the basin was approximately 204,000 net acres (245,000 gross).

Acquisitions and Divestitures

Hastings Complex Sale. In February 2009, we completed the sale of our principal interests in the Hastings Complex to Denbury for approximately $197.7 million. We retained the right to back into a working interest of approximately 22.3% in the CO_2 project Denbury is pursuing at the Hastings Complex after it recoups certain costs. In December 2010, Denbury commenced injecting CO_2 at the Hastings Complex and has begun production at the field in January 2012.

Sale of Other Texas Assets. We sold our producing assets in Texas in a series of transactions that were completed in the second quarter of 2010 to multiple purchasers for aggregate net proceeds of $98.1 million (after closing adjustments and related expenses).

Other. We have an active acreage acquisition program and we regularly engage in acquisitions (and, to a lesser extent, dispositions) of oil and natural gas properties, primarily in and around our existing core areas of operations, including transactions in each of 2009, 2010 and 2011.

Trends Affecting our Results of Operations

Oil and Natural Gas Prices. Historically, prices received for our oil and natural gas production have been volatile and unpredictable, and that volatility is expected to continue. Changes in the market prices for oil and natural gas directly impact many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth, the carrying value of our oil and natural gas properties and borrowing capacity under our revolving credit facility, all of which depend in part upon those prices. We employ a hedging strategy to reduce the variability of the prices we receive for our production and provide a minimum revenue stream. As of February 14, 2012 we had hedge contract floors covering 8,500 barrels of oil per day and 29.5 million cubic feet of natural gas per day for 2012. We have also secured hedge contracts for portions of our 2013, 2014 and 2015 production. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Derivative Transactions" for further details concerning our hedging activities. Additionally, the sales contracts under which we have historically sold a significant portion of our oil are based on the NYMEX WTI ("WTI") crude price index and these contracts expire at the end of the first quarter of 2012. To replace the expiring contracts, we have entered into new sales contracts based on certain Southern California crude price indexes, which traded at a premium to WTI throughout 2011 and have more closely tracked with the Inter-Continental Exchange Brent crude price index ("Brent"). We have also entered into a new sales contract related to oil produced from our South Ellwood field which is more favorable than the previous contract because, effective January 31, 2012, we are able to deliver our oil through a common carrier pipeline rather than via barge.

Expected Production. As a result of sustained depressed natural gas prices, during 2011 we emphasized our oil projects in Southern California relative to our natural gas projects in the Sacramento Basin. We plan to continue this strategy in 2012, with approximately 48% of our planned capital expenditures allocated to our legacy Southern California fields and 39% allocated to our onshore Monterey shale program. Given our expected increase in capital spending related to our oil producing legacy Southern California assets in 2012, we expect the production ratio of oil to natural gas to increase in 2012 relative to 2011. We also expect overall production in 2012 to be similar to production in 2011 on a BOE basis. Our expectations with respect to future production rates are subject to a number of uncertainties, including those associated with third party services, the availability of drilling rigs, oil and natural gas prices, events resulting in unexpected downtime, permitting issues, drilling success rates, including our ability to identify productive intervals and the drilling and completion techniques necessary to achieve commercial production in the onshore Monterey shale on a broader scale, and other factors, including those referenced in the "Risk Factors" section this Annual Report.

Lease Operating Expenses. Lease operating expenses ("LOE") of $14.64 per BOE for 2011 were higher than our 2010 results of $12.65 per BOE. We expect our 2012 LOE per BOE to be higher relative to 2011 primarily as a result of a continued shift in our focus to oil projects as compared to natural gas projects. Our expectations with respect to future expenses are subject to numerous risks and uncertainties, including those described and referenced in the preceding paragraph.

Property and Production Taxes. Property and production taxes of $0.99 per BOE for 2011 were relatively flat when compared to our 2010 results of $1.01 per BOE. We expect our 2012 property and production taxes to remain relatively flat on a per BOE basis compared to our 2011 results. As with lease operating expenses, our expectations with respect to future property and production taxes are subject to numerous risks and uncertainties.

Transportation Expenses. Transportation expenses were $9.3 million for 2011 and $9.1 million in 2010. We expect that our transportation expenses will decrease in 2012 compared to 2011 as a result of the completion of the onshore pipeline that transports the oil produced from our South Ellwood field. This pipeline will eliminate the use of the double-hulled barge that was used throughout 2011.

General and Administrative Expenses. General and administrative expenses increased slightly to $4.96 per BOE (excluding share-based compensation charges of $0.88 per BOE and costs of $0.26 per BOE related to the evaluation by the special committee of the Marquez Proposal) in 2011 compared to $4.78 per BOE for 2010 (excluding share-based compensation charges of $0.68 per BOE and one-time charges of $0.19 per BOE for severance payments resulting from the sale of our Texas producing properties). Excluding share-based compensation charges and special committee related charges, on a per BOE basis, we expect our G&A costs to increase in 2012 compared to 2011. As with our lease operating expenses and property and production taxes, our expectations with respect to G&A costs are subject to numerous risks and uncertainties.

Depreciation, Depletion and Amortization (DD&A). DD&A for 2011 of $13.35 per BOE increased from our 2010 DD&A of $11.79 per BOE. We expect our 2012 DD&A to increase on a per BOE basis compared to our full year 2011 results. As with lease operating expenses, property and production taxes and G&A expenses, our expectations with respect to DD&A expenses are subject to numerous risks and uncertainties.

Interest Expense. As a result of the refinancing of our second lien term loan in the first quarter of 2011 (see "—Capital Resources and Requirements"), we replaced $455.3 million of variable rate debt with $500.0 million of 8.875% fixed rate debt. Additionally, because our second lien term loan was subject to variable interest rates, we had entered into interest rate derivative contracts to mitigate our interest rate risk and, as a result, $500.0 million of variable rate borrowings effectively bore interest at approximately 7.8%. In conjunction with the refinancing transaction in the first quarter of 2011, we settled the interest rate derivative contracts.

Unrealized Derivative Gains and Losses. Unrealized gains and losses result from mark-to-market valuations of derivative positions that are not accounted for as cash flow hedges and are reflected as unrealized commodity derivative gains or losses in our income statement. Payments actually due to or from counterparties in the future on these derivatives will typically be offset by corresponding changes in prices ultimately received from the sale of our production. We have incurred significant unrealized gains and losses in recent periods and may continue to incur these types of gains and losses in the future.

Income Tax Expense (Benefit). We incurred losses before income taxes in 2008 and 2009 as well as taxable losses in each of the tax years from 2008 through 2011. These losses and expected future taxable losses were a key consideration that led us to conclude that we should maintain a full valuation allowance against our net deferred tax assets at December 31, 2010 and December 31, 2011 since we could not conclude that it is more likely than not that the net deferred tax assets will be fully realized.

As long as we continue to conclude that we have a need for a full valuation allowance against our net deferred tax assets, we likely will not have any income tax expense or benefit other than for federal alternative minimum tax expense, a release of a portion of the valuation allowance for net operating loss carryback claims or for state income taxes. Future events or new evidence which may lead us to conclude that it is more likely than not that our net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings; consistent and sustained pre-tax earnings; sustained or continued improvements in oil and natural gas commodity prices; consistent, meaningful production and proved reserves from our onshore Monterey shale project; and meaningful production and proved reserves from the CO_2 project at the Hastings Complex. We will continue to evaluate whether the valuation allowance is needed in future reporting periods.

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. No pro forma adjustments have been made for the acquisitions and divestitures of oil and natural gas properties, which will affect the comparability of the data below. The information set forth below is not necessarily indicative of future results.

	Years Ended December 31,		
	2009	2010	2011
Production Volume(1):			
Oil (MBbls)	3,402	2,792	2,441
Natural gas (MMcf)	24,748	23,196	23,923
MBOE(2)	7,527	6,658	6,428
Daily Average Production Volume:			
Oil (Bbls/d)	9,321	7,649	6,688
Natural gas (Mcf/d)	67,803	63,551	65,542
BOE/d(2)	20,622	18,241	17,612
Oil Price per Bbl Produced (in dollars):			
Realized price	$ 50.60	$ 68.86	$ 91.00
Realized commodity derivative gain (loss)	(0.95)	(1.77)	(2.48)
Net realized price	$ 49.65	$ 67.09	$ 88.52
Natural Gas Price per Mcf Produced (in dollars):			
Realized price	$ 3.84	$ 4.34	$ 4.02
Realized commodity derivative gain (loss)	2.58	1.70	1.03
Net realized price	$ 6.42	$ 6.04	$ 5.05
Expense per BOE:			
Lease operating expenses	$ 12.65	$ 12.65	$ 14.64
Production and property taxes	$ 1.35	$ 1.01	$ 0.99
Transportation expenses	$ 0.42	$ 1.37	$ 1.45
Depletion, depreciation and amortization	$ 11.46	$ 11.79	$ 13.35
General and administrative expense, net(3)	$ 4.91	$ 5.64	$ 6.10
Interest expense	$ 5.44	$ 6.10	$ 9.51

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

(2) BOE is determined using the ratio of one barrel of oil or natural gas liquids to six Mcf of natural gas.

(3) Net of amounts capitalized.

Comparison of Year Ended December 31, 2011 to Year Ended December 31, 2010

Oil and Natural Gas Sales. Oil and natural gas sales increased $32.8 million (11%) to $323.4 million in 2011 from $290.6 million in 2010. The increase was due to higher realized oil prices, partially offset by a decrease in oil production and lower realized natural gas prices, as described below.

Oil sales increased by $37.2 million (20%) in 2011 to $227.2 million compared to $190.0 million in 2010. Oil production decreased by 13%, with production of 2,441 MBbl in 2011 compared to 2,792 MBbl in 2010. The production decrease was partially due to the sales of our remaining producing properties in Texas in the second quarter of 2010. Excluding production from the Texas properties, production decreased by 239 MBbls (9%) from 2,680 MBbls in 2010 to 2,441 MBbls in 2011. The decrease is primarily due to natural production decline at the Sockeye, South Ellwood and West Montalvo fields. Our average realized price for oil increased $22.14 (32%) from $68.86 per Bbl in 2010 to $91.00 per Bbl in 2011.

Natural gas sales decreased $4.4 million (4%) in 2011 to $96.2 million compared to $100.6 million in 2010. Natural gas production increased by 727 MMcf (3%), with production of 23,923 MMcf in 2011 compared to 23,196 MMcf in 2010. Excluding production from the Texas properties, natural gas production increased by 1,068 MMcf (5%) from 22,855 MMcf in 2010 to 23,923 MMcf in 2011. The increase is due in large part to successful drilling and recompletion activity in the Sacramento Basin, primarily in the Grimes field, in the latter half of 2010 and during 2011. Our average realized price for natural gas decreased $0.32 (7%) from $4.34 per Mcf for 2010 to $4.02 per Mcf for 2011.

Other Revenues. Other revenues increased by $0.7 million (15%) to $5.4 million in 2011 from $4.7 million in 2010. Effective April 2010, we entered into a contract related to the double-hulled barge that transported oil produced at our South Ellwood field (see "—*Transportation Expenses"*). The contract allowed us to sub-charter the barge and retain a major portion of the revenues from those activities. Per terms of the contract, there is a minimum notification period for termination; as such the contract will be terminated in May 2012 since the common carrier pipeline is now used to transport oil production from the field.

Lease Operating Expenses. Lease operating expenses ("LOE") increased $9.8 million (12%) to $94.1 million in 2011 from $84.3 million in 2010. Excluding the Texas properties, production expenses increased $12.5 million (15%) from $81.6 million in 2010 to $94.1 million in 2011. The increase in LOE is primarily due to (i) costs incurred to return Platform Grace to production, which had been shut-in since the end of 2008 and (ii) non-recurring maintenance performed at Dos Cuadras, Platform Gail and Platform Holly, primarily in the third quarter of 2011. On a per unit basis, LOE was $14.64 per BOE in 2011 and $12.65 per BOE in 2010. Excluding the Texas assets, LOE per BOE increased from $12.57 per BOE in 2010 to $14.64 per BOE in 2011.

Production and Property Taxes. Production and property taxes decreased $0.3 million (5%) to $6.4 million in 2011 from $6.7 million in 2010. The decrease was primarily due to the sale of our remaining Texas properties in the second quarter of 2010. Excluding the Texas properties, production and property taxes remained relatively flat at $6.4 million in 2011 and $6.3 million in 2010.

Transportation Expenses. Transportation expenses increased $0.2 million (2%) to $9.3 million in 2011 from $9.1 million in 2010. In April 2010, a transportation contract became effective relating to the time-charter of a double-hulled barge to transport oil produced from our South Ellwood field. Under that contract we paid a flat day rate, regardless of our usage of the barge, but had the ability to sub-charter the vessel when it is not in use transporting production from the South Ellwood field (see "—*Other Revenues*"). The increase in 2011 compared to 2010 was the result of the transportation contract being in place for the full year in 2011 compared to nine months in 2010.

Depletion, Depreciation and Amortization (DD&A). DD&A expense increased $7.3 million (9%) to $85.8 million in 2011 from $78.5 million in 2010. The increase is due to a higher depletion rate primarily due to higher amortizable bases at each of the quarterly periods in 2011 compared to 2010. DD&A expense on a per unit basis increased by $1.56 (13%) from $11.79 per BOE for 2010 to $13.35 per BOE for 2011.

Accretion of Abandonment Liability. Accretion expense remained relatively constant at $6.4 million in 2011 compared to $6.2 million in 2010.

General and Administrative (G&A). The following table summarizes the components of general and administrative expense incurred during the periods indicated (in thousands):

	Years Ended December 31,	
	2010	**2011**
General and administrative costs	$ 52,052	$ 54,852
Share-based compensation costs	6,930	9,720
One-time severance costs	1,254	—
Special Committee-related costs	—	1,642
General and administrative costs capitalized	(22,682)	(27,028)
General and administrative expense	$ 37,554	$ 39,186

G&A expense increased $1.6 million (4%) to $39.2 million in 2011 compared to $37.6 million in 2010. The overall increase in G&A costs was primarily due to (i) non-cash share-based compensation expense of $5.7 million (net of amount capitalized) charged to G&A in 2011 compared to $4.5 million (net of amount capitalized) in 2010, (ii) a higher annual bonus accrual for 2011 based on a higher level of achievement of specified bonus metrics in 2011, (iii) increased travel costs in 2011 and (iv) costs incurred of $1.6 million in 2011 related to the evaluation by the special committee of the board of directors of the Marquez Proposal. The increases were partially offset by (i) higher capitalization in 2011 as a result of an increased focus on onshore Monterey shale activities and other development related activity in 2011 (ii) one-time severance payments of $1.3 million in 2010 related to the sale of our Texas properties and the related closure of our Texas operations and (iii) a decrease in professional fees incurred in 2011 compared to 2010. Excluding the effect of the non-cash share-based compensation expense, special committee-related costs and one-time severance charges, G&A expense increased to $4.96 per BOE in 2011 from $4.78 per BOE in 2010.

Interest Expense, Net. Interest expense, net of interest income, increased $20.5 million (51%) to $61.1 million in 2011 from $40.6 million in 2010. The increase was primarily the result of the refinancing of our second lien term loan in February 2011 with the issuance of our 8.875% senior notes. The interest rate on our second lien term loan, which was outstanding during 2010, averaged approximately 4.4% per annum during the year.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs was $2.3 million in 2011 compared to $2.4 million in 2010. The costs incurred relate to our loan agreements and are amortized over the estimated lives of the agreements.

Interest Rate Derivative (Gains) Losses, Net. In conjunction with the retirement of our second lien term loan in February 2011, we settled our outstanding interest rate swap contracts for $38.1 million. The result of settlement of the contracts and other activity prior to settlement resulted in an unrealized interest rate derivative gain of $40.1 million and a realized interest rate derivative loss of $41.1 million. In 2010, we recognized an unrealized interest rate derivative loss of $13.7 million and a realized interest rate derivative loss of $18.1 million.

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt in 2011 of $1.4 million resulting from the repayment of our second lien term loan. The loss related primarily to the write off of unamortized deferred financing costs associated with the second lien term loan.

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

	Years Ended December 31,	
	2010	2011
Realized commodity derivative (gains) losses	$(53,501)	$(30,656)
Amortization of commodity derivative premiums	24,808	10,058
Unrealized commodity derivative (gains) losses for changes in fair value	(39,356)	(20,051)
Commodity derivative (gains) losses	$(68,049)	$(40,649)

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative gains in both 2011 and 2010 reflect the settlement of contracts at prices below the relevant strike prices. In the fourth quarter of 2011, we settled all of our 2013 natural gas hedge contracts (except for basis swaps) which resulted in a non-recurring gain of $12.0 million, which is reflected in the 2011 realized commodity derivative (gains) losses. In the fourth quarter of 2010, we settled certain 2011 gas puts and collars which resulted in realized gains of $19.1 million and are reflected in the 2010 realized commodity derivative gains. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. Derivative premiums are amortized over the term of the underlying derivative contracts.

Income Tax Expense (Benefit). We incurred losses before income taxes in 2008 and 2009 as well as taxable losses in each of the tax years from 2008 through 2011. These losses and expected future taxable losses were a key consideration that led us to conclude that we should maintain a full valuation allowance against our net deferred tax assets at December 31, 2010 and December 31, 2011 since we could not conclude that it is more likely than not that the net deferred tax assets will be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during periods in which those temporary differences become deductible. As long as we continue to conclude that we have a need for a full valuation allowance against our net deferred tax assets, we likely will not have any income tax expense or benefit other than for federal alternative minimum tax expense, a release of a portion of the valuation allowance for net operating loss carryback claims, or for state income taxes. However, we continue to evaluate the existing evidence to determine the point at which we can conclude that it is more likely than not that we will be able to realize our net deferred tax assets and, as a result, reverse all or a portion of the valuation allowance. The income tax benefit for 2010 primarily relates to an increase in the estimated net operating loss carryback claims for the 2003 through 2005 tax years and a reduction in the amount owed for prior year state income taxes. Additionally, we amended prior year returns in 2010 for certain share based compensation matters, which will result in additional income tax refunds. Due to our valuation allowance, there was no income tax expense (benefit) recorded for the year ended December 31, 2011.

Net Income (Loss). Net income for 2011 was $62.3 million compared to net income of $67.5 million for 2010. The change between years is the result of the items discussed above.

Comparison of Year Ended December 31, 2010 to Year Ended December 31, 2009

Oil and Natural Gas Sales. Oil and natural gas sales increased $23.4 million (9%) to $290.6 million in 2010 from $267.2 million in 2009. The increase was due to increases in realized oil and natural gas prices, partially offset by a decrease in production as described below.

Oil sales increased by $17.9 million (10%) in 2010 to $190.0 million compared to $172.1 million in 2009. Oil production decreased by 18%, with production of 2,792 MBbl in 2010 compared to 3,402 MBbl in 2009. The production decrease was due in large part to the sale of the Hastings Complex in early February 2009 and the sales of our remaining producing properties in Texas in the second quarter of 2010. Excluding production from the Texas properties, production decreased by 285 MBbls (10%) from 2,965 MBbls in 2009 to 2,680 MBbls in 2010. This decrease is primarily due to (i) the natural decline of production at the Sockeye and South Ellwood fields and (ii) reduced production at the Dos Cuadras field as a result of certain wells being taken offline due to temporary operational difficulties. Our average realized price for oil increased $18.26 (36%) from $50.60 per Bbl in 2009 to $68.86 per Bbl in 2010.

Natural gas sales increased $5.5 million (6%) in 2010 to $100.6 million compared to $95.1 million in 2009. Natural gas production decreased 6%, with production of 23,196 MMcf in 2010 compared to 24,748 MMcf in 2009. The decrease was due in large part to the sales of our producing properties in Texas during the second quarter of 2010. Excluding production from the Texas properties, natural gas production decreased by 428 MMcf (2%) from 23,283 MMcf in 2009 to 22,855 MMcf in 2010. The slight decrease in production is primarily due to the natural decline of production from wells in the Sacramento Basin, the majority of which has been offset by production from newly drilled and recompleted wells. Our average realized price for natural gas increased $0.50 (13%) from $3.84 per Mcf in 2009 to $4.34 per Mcf for 2010.

Other Revenues. Other revenues increased by $1.4 million (42%) to $4.7 million in 2010 from $3.3 million in 2009. The increase is primarily due to a contract that became effective in April 2010, related to the double-hulled barge that transported oil produced at our South Ellwood field (see "—*Transportation Expenses*"). The contract allowed us to sub-charter the barge and retain the revenues from those activities. The increase in other revenues is the result of sub-charter activities in 2010.

Lease Operating Expenses. Lease operating expenses ("LOE") decreased $10.9 million (12%) to $84.3 million in 2010 from $95.2 million in 2009. The decrease was primarily due to the sale of the Hastings Complex in early February 2009 and the sale of our remaining Texas properties in the second quarter of 2010. Excluding the Texas properties, production expenses decreased $1.8 million (2%) from $83.4 million in 2009 to $81.6 million in 2010. The decrease was primarily due to lower non-recurring maintenance costs incurred at our South Ellwood field in 2010 compared to 2009. On a per unit basis, LOE was $12.65 per BOE in both 2009 and 2010. Excluding the Texas assets, LOE per BOE increased from $12.18 per BOE in 2009 to $12.57 per BOE in 2010. The increase on a per BOE basis is the result of lower production levels in 2010 compared to 2009.

Production and Property Taxes. Production and property taxes decreased $3.4 million (34%) to $6.7 million in 2010 from $10.1 million in 2009. The decrease was partially due to the sale of the Hastings Complex in early February 2009 and the sale of our remaining Texas properties in the second quarter of 2010. Excluding the Texas properties, production and property taxes decreased $1.9 million (23%) from $8.1 million in 2009 to $6.2 million in 2010. The decrease was primarily due to lower supplemental property taxes incurred in 2010 as compared to 2009 resulting from lower gas prices and lower assessed mineral rights valuations for drilling and recompletion activities.

Transportation Expenses. Transportation expenses increased $5.9 million (188%) to $9.1 million in 2010 from $3.2 million in 2009. On a per BOE basis, transportation expenses increased $0.95 per BOE, from $0.42 per BOE in 2009 to $1.37 per BOE in 2010. The increase is primarily due to the contract described in "—*Other Revenues*", related to the time-charter of a double-hulled barge to transport oil produced from our South Ellwood field. Under that contract we paid a flat day rate, regardless of our usage of the barge, but had the ability to sub-charter the vessel when it is not in use transporting production from the South Ellwood field (see "—*Other Revenues*"). We also incurred additional transportation costs from the use of a single-hulled barge during the transition period to the double-hulled barge, which was completed late in the fourth quarter of 2010.

Depletion, Depreciation and Amortization (DD&A). DD&A expense decreased $7.7 million (9%) to $78.5 million in 2010 from $86.2 million in 2009. The decrease is related to (i) a lower amortizable base in 2010 resulting from the application of the net proceeds from the sales of our Texas producing properties and (ii) lower production in 2010 compared to 2009. DD&A expense on a per unit basis increased by $0.33 (3%) from $11.46 per BOE for 2009 to $11.79 per BOE for 2010.

Accretion of Abandonment Liability. Accretion expense increased $0.4 million (8%) to $6.2 million in 2010 from $5.8 million in 2009. The increase is primarily due to accretion from new wells drilled and completed in 2009 and 2010.

General and Administrative (G&A). The following table summarizes the components of general and administrative expense incurred during the periods indicated (in thousands):

	Years Ended December 31,	
	2009	**2010**
General and administrative costs	$ 58,135	$ 52,052
Share-based compensation costs	3,890	6,930
One-time severance costs	—	1,254
General and administrative costs capitalized	(25,086)	(22,682)
General and administrative expense	$ 36,939	$ 37,554

G&A expense increased $0.7 million (2%) to $37.6 million in 2010 from $36.9 million in 2009. The overall increase in G&A costs was primarily due to increases resulting from: (i) lower capitalized G&A costs in 2010 compared to the amount capitalized in 2009 due to lower levels of drilling activity in the first quarter of 2010, (ii) one-time severance payments of $1.3 million in 2010 related to the sale of our Texas properties and the related closure of our Texas operations and (iii) non-cash share-based compensation expense of $4.5 million (net of amount capitalized) charged to G&A in 2010 compared to $2.1 million (net of amount capitalized) in 2009. We issued annual restricted stock awards in the first quarter of both 2010 and 2009. The fair value of the awards issued in the 2010 period was significantly greater than the grants in the 2009 period due to the increase in our stock price between the periods, which contributed to the increase in non-cash share-based compensation expense. These increases were partially offset by lower other general and administrative costs resulting from the closing of our Texas office and other G&A decreases. Excluding the effect of the non-cash share- based compensation expense and one-time severance charges, G&A expense increased to $4.78 per BOE in 2010 from $4.63 per BOE in 2009. The increase on a per unit basis is primarily the result of lower production levels in 2010 compared with 2009.

Interest Expense, Net. Interest expense, net of interest income, remained relatively constant at $40.6 million in 2010 compared to $41.0 million in 2009.

Amortization of Deferred Loan Costs. Amortization of deferred loan costs was $2.4 million in 2010 compared to $2.9 million in 2009. The costs incurred relate to our loan agreements, which are amortized over the estimated lives of the agreements.

Interest Rate Derivative (Gains) Losses, Net. Changes in the fair value of our interest rate swap derivative instruments resulted in unrealized losses of $13.7 million in 2010 and unrealized gains of $1.8 million in 2009. Unrealized interest rate (gains) losses represent the change in the fair value of our interest rate derivative contracts from period to period based on estimated future interest rates at the end of the reporting period. Realized interest rate swap losses were $18.1 million in 2010 and $18.4 million in 2009.

Loss on Extinguishment of Debt. We recognized losses on extinguishment of debt in 2009 of $8.5 million related to repayment of the financed derivative premiums balance in May 2009 and the refinancing of our $150 million senior notes in October 2009.

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

	Years Ended December 31,	
	2009	**2010**
Realized commodity derivative (gains) losses	$(68,429)	$(53,501)
Amortization of commodity derivative premiums	22,661	24,808
Unrealized commodity derivative (gains) losses for changes in fair value	71,511	(39,356)
Commodity derivative (gains) losses	$ 25,743	$(68,049)

Realized commodity derivative gains or losses represent the difference between the strike prices in the contracts settled during the period and the ultimate settlement prices. The realized commodity derivative gains in both 2010 and 2009 reflect the settlement of contracts at prices below the relevant strike prices. In the first quarter of 2009, we unwound certain 2009 oil collars and certain 2009 gas puts which resulted in non-recurring gains of $7.7 million which are reflected in the 2009 realized commodity derivative gains. In the fourth quarter of 2010, we settled certain 2011 gas puts and collars which resulted in realized gains of $19.1 million which are reflected in the 2010 realized commodity derivative gains. Unrealized commodity derivative (gains) losses represent the change in the fair value of our open derivative contracts from period to period. Derivative premiums are amortized over the term of the underlying derivative contracts.

Income Tax Expense (Benefit). We incurred losses before income taxes in 2008 and 2009 as well as taxable losses in each of the tax years from 2008 through 2010. These losses were a key consideration that led us to provide a valuation allowance against our net deferred tax assets at December 31, 2009 and December 31, 2010 since we could not conclude that it is more likely than not that the net deferred tax assets will be fully realized on future tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. As long as we continue to conclude that we have a need for a full valuation allowance against our net deferred tax assets, we likely will not have any income tax expense or benefit other than for federal alternative minimum tax expense, a release of a portion of the valuation allowance for net operating loss carryback claims, or for state income taxes. The current tax benefit for 2009 of $14.4 million reflects a reduction of prior year current tax expense (a $6.0 million benefit) and, due to the temporary five-year carryback period that became available in 2009, a carryback of net operating losses (a $8.4 million benefit). The income tax benefit we recorded for 2010 primarily relates to an increase in the estimated net operating loss carryback claims for the 2003 through 2005 tax years and a reduction in the amount owed for prior year state income taxes. Additionally, we amended prior year returns in 2010 for certain share based compensation matters, which will result in additional income tax refunds.

Net Income (Loss). Net income for 2010 was $67.5 million compared to net loss of $47.3 million for 2009. The change between years is the result of the items discussed above.

Liquidity and Capital Resources

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

Cash Flows

	Years Ended December 31,		
	2009	2010	2011
	(in thousands)		
Cash provided by (used in) operating activities	$ 118,691	$ 160,673	$ 125,496
Cash provided by (used in) investing activities	(1,953)	(108,296)	(246,481)
Cash provided by (used in) financing activities	(116,510)	(47,772)	124,126

Net cash provided by operating activities was $125.5 million in 2011 compared with $160.7 million in 2010 and $118.7 million in 2009. Cash flows from operating activities in 2011 as compared to 2010 were unfavorably impacted by the settlement of our interest rate derivative contracts in the first quarter of 2011 for $38.1 million (see "—Capital Resources and Requirements"), partially offset by higher realized oil prices during 2011. Cash flows from operating activities in 2010 as compared to 2009 were favorably impacted by increases in commodity prices, partially offset by decreased production.

Net cash used in investing activities was $246.5 million in 2011 compared with net cash used of $108.3 million in 2010 and net cash used of $2.0 million in 2009. The primary investing activities in 2011 were $244.6 million in capital expenditures on oil and natural gas properties related to our capital expenditure program. The primary investing activities in 2010 were $208.4 million in capital expenditures on oil and natural gas properties related to our capital expenditure program, partially offset by the receipt of $107.4 million in net cash proceeds from the sales of our Texas producing properties in the second quarter of 2010 and the sale of our Cat Canyon field in the fourth quarter of 2010. The primary investing activities in 2009 were $174.8 million in capital expenditures for our oil and gas exploration and development programs together with $21.3 million paid to acquire certain Sacramento Basin assets. These total expenditures of $196.1 million were offset by the receipt of $197.7 million in cash proceeds from the sale of our Hastings Complex in Texas.

Net cash provided by financing activities was $124.1 million in 2011 compared to net cash used of $47.8 million in 2010 and net cash used of $116.5 million in 2009. The primary financing activities in 2011 were the two capital raising transactions we completed as described below in "—Capital Resources and Requirements". In conjunction with the capital raising transactions, we repaid (i) the outstanding principal of $455.3 million related to our second lien term loan and (ii) the outstanding balance of $45.0 million on our revolving credit facility. Additionally, subsequent to the completion of those transactions, we incurred net borrowings on our revolving credit facility of $43.0 million. The primary financing activities in 2010 were $22.9 million in net payments made on our revolving credit facility and $39.2 million of principal repayments on the second lien term loan, both of which were primarily funded by proceeds from the sales of our producing properties in Texas and our Cat Canyon field. The primary financing activities in 2009 were as follows: (i) we made net repayments of $77.2 million on our revolving credit facility and $5.5 million of principal payments on the second lien term loan, both of which were primarily funded with proceeds from the Hastings sale, (ii) we paid approximately $15.3 million in May 2009 to settle financed derivative premiums, (iii) in October 2009, we refinanced our 8.50% senior notes with the issuance of our 11.50% senior notes, which resulted in a principal repayment of $150 million and a premium payment of $3.3 million. We received cash of $142.5 million, net of the $7.5 million original issue discount, from the issuance of the 11.50% senior notes. We incurred $2.9 million in debt issuance costs related to the senior notes refinancing. Additionally, we incurred $1.9 million of debt issuance costs related to the third amendment and restatement of the agreement governing the revolving credit facility, which we entered into in December 2009.

Capital Resources and Requirements

In the first quarter of 2011, we completed two capital raising transactions which provided us with additional liquidity. First, we issued 4.6 million shares of common stock at a price to the public of $18.75 per share. We received net proceeds of approximately $82.2 million from the equity offering after deducting offering-related expenses. Second, we issued $500 million of 8.875% senior unsecured notes which are due in February 2019. We received net proceeds of approximately $490.3 million from the notes offering, after deducting offering-related expenses. The proceeds from the two transactions were used to repay the outstanding principal of $455.3 million and accrued interest of $1.6 million related to our second lien term loan, settle the related interest rate swap contracts for $38.1 million and repay the outstanding balance of $45.0 million on our revolving credit facility.

We plan to make substantial capital expenditures in the future for the acquisition, exploration, exploitation and development of oil and natural gas properties. We expect that our exploration, exploitation and development capital expenditures, which were $255 million in 2011, will be approximately $255 million in 2012. We expect to fund our 2012 capital expenditures budget primarily with cash flow from operations, supplemented with borrowings under our revolving credit facility. Additionally, we continue to pursue joint venture transactions related to our onshore Monterey shale acreage and potential sales of non-core assets. We have significant flexibility to reduce capital expenditures if warranted by business conditions or limits on our capital resources. Uncertainties relating to our capital resources and requirements include the possibility that one or more of the counterparties to our hedging arrangements may fail to perform under the contracts, the effects of changes in commodity prices and differentials, results from our onshore Monterey shale program, which could lead us to accelerate or decelerate activities depending on the extent of our success in developing the program, and the possibility that we will pursue one or more significant acquisitions that would require additional debt or equity financing.

Amended Revolving Credit Facility. In April 2011, we entered into a fourth amended and restated credit agreement governing our revolving credit facility, which has a maturity date of March 31, 2016. The agreement contains customary representations, warranties, events of default, indemnities and covenants, including covenants that restrict our ability to incur indebtedness and require us to maintain specified ratios of current assets to current liabilities and debt to EBITDA. The minimum ratio of current assets to current liabilities (as those terms are defined in the agreement) is one to one; the maximum ratio of debt to EBITDA (as defined in the agreement) is four to one. While we do not expect to be in violation of any of our debt covenants during 2012, we believe that it will be important to monitor the debt to EBITDA ratio requirement, especially if our EBITDA is less than we expect due to operational problems or other factors, or if our borrowing needs are greater than we expect. The agreement requires us to reduce amounts outstanding under the facility with the proceeds of certain transactions or events, including sales of assets, in certain circumstances. The revolving credit facility is secured by a first priority lien on substantially all of our assets.

Loans under the revolving credit facility designated as "Base Rate Loans" bear interest at a floating rate equal to (i) the greater of (x) Bank of Montreal's announced base rate, (y) the overnight federal funds rate plus 0.50% and (z) the one-month LIBOR plus 1.0%, plus (ii) an applicable margin ranging from 0.75% to 1.75%, based upon utilization. Loans designated as "LIBO Rate Loans" under the revolving credit facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.75% to 2.75%, based upon utilization. A commitment fee of 0.5% per annum is payable with respect to unused borrowing availability under the facility.

The revolving credit facility has a total capacity of $500.0 million, but is limited by a borrowing base, which is currently established at $200.0 million. The borrowing base is subject to redetermination twice each year, and may be redetermined at other times at our request or at the request of the lenders. Lending commitments under the facility have been allocated at various percentages to a syndicate of 11 banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with events in the credit markets. A failure of any members of the syndicate to fund under the facility, or a reduction in the borrowing base, would adversely affect our liquidity. As of February 14, 2012, we have $35.0 million outstanding under the facility and $161.2 million in available borrowing capacity, net of the outstanding balance and $3.8 million of outstanding letters of credit.

Second Lien Term Loan and 8.875% Senior Notes. We entered into a $500.0 million senior secured second lien term loan agreement in May 2007. Prior to repayment as described below, the term loan facility was secured by a second priority lien on substantially all of our assets and was due to mature on May 8, 2014. Loans under the second lien term loan facility designated as "Base Rate Loans" bore interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and the administrative agent's announced base rate, plus (ii) 3.00%. Loans designated as "LIBO Rate Loans" bore interest at LIBOR plus 4.00%.

In February 2011, we issued $500 million in 8.875% senior unsecured notes due in February 2019 at par. Concurrently with the sale of the 8.875% senior notes, we repaid in full the outstanding principal balance of $455.3 million on the second lien term loan, plus accrued interest of $1.6 million.

The 8.875% senior notes pay interest semi-annually in arrears on February 15 and August 15 of each year. We may redeem the notes prior to February 15, 2015 at a "make whole premium" defined in the indenture. Beginning February 15, 2015, we may redeem the notes at a redemption price of 104.438% of the principal amount and declining to 100% by February 15, 2017. The 8.875% senior notes are senior unsecured obligations and contain operational covenants that, among other things, limit our ability to make investments, incur additional indebtedness or create liens on our assets.

11.50% Senior Notes. In October 2009, we issued $150.0 million of 11.50% senior unsecured notes due in October 2017 at a price of 95.03% of par. The senior notes pay interest semi-annually in arrears on April 1 and October 1 of each year. We may redeem the senior notes prior to October 1, 2013 at a "make-whole price" defined in the indenture. Beginning October 1, 2013, we may redeem the notes at a redemption price equal to 105.75% of the principal amount and declining to 100% by October 1, 2016. The indenture governing the notes 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 amounts due under our debt agreements, that portion of our cash flow is not available for other purposes. Our ability to make scheduled interest payments on our indebtedness and pursue our capital expenditure plan will depend to a significant extent on our financial and operating performance, which is subject to prevailing economic conditions, commodity prices and a variety of other factors. If our cash flow and other capital resources are insufficient to fund our debt service obligations and our capital expenditure budget, we may be forced to reduce or delay scheduled capital projects, sell material assets or operations and/or seek additional capital. Needed capital may not be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness and certain other means is limited by covenants in our debt agreements. In addition, pursuant to mandatory prepayment provisions in our revolving credit facility, our ability to respond to a shortfall in our expected liquidity by selling assets or incurring additional indebtedness would be limited by provisions in the facility that require us to use some or all of the proceeds of such transactions to reduce amounts outstanding under the facility in some circumstances. If we are unable to obtain funds when needed and on acceptable terms, we may not be able to complete acquisitions that may be favorable to us, meet our debt obligations or finance the capital expenditures necessary to replace our reserves.

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Commitments and Contingencies

As of December 31, 2011, the aggregate amounts of contractually obligated payment commitments for the next five years were as follows (in thousands):

	Less than One Year	1 to 3 Years	3 to 5 Years	After 5 years	Total(1)
Long-term debt(2)	$ —	$ —	$ 43,000	$643,958	$ 686,958
Interest on senior notes	61,625	123,250	123,250	107,123	415,248
Office, property and equipment leases	2,748	4,966	3,865	6,359	17,938
Total	$64,373	$128,216	$170,115	$757,440	$1,120,144

(1) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts, obligations to taxing authorities or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations, due to the uncertainty surrounding the ultimate settlement amounts and timing of these obligations. Our total asset retirement obligations were $92.5 million at December 31, 2011.

(2) Amounts related to interest expense on our revolving credit facility is not included in the table above because the interest rate is variable. See "Capital Resources and Requirements" for a discussion of the terms related to the revolving credit facility. During the years ended December 31, 2009, 2010 and 2011, we incurred interest expense on the revolving credit facility of $1.4 million, $1.3 million and $0.5 million, respectively.

Off-Balance Sheet Arrangements

At December 31, 2011, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies and Estimates

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

Reserve Estimates

Our estimates of oil and natural gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as in the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulation by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance, ad valorem and excise taxes, development costs and workover and remedial costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on the likelihood of recovery and estimates of the future net cash flows expected from them may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value and the rate of depletion of the oil and natural gas properties. For example, oil and natural gas price changes affect the estimated economic lives of oil and natural gas properties and therefore cause reserve revisions. Our December 31, 2011 estimate of net proved oil and natural gas reserves totaled 95.9 MMBOE. 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 1% lower. In addition, our proved reserves are concentrated in a relatively small number of wells. At December 31, 2011, 35% of our proved reserves were concentrated in our 20 largest wells. As a result, any changes in proved reserves attributable to such individual wells could have a significant effect on our total reserves. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

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

We follow the full cost method of accounting for oil and natural gas properties. Under this method, all productive and nonproductive costs incurred in connection with the acquisition of, exploration for and exploitation and development of oil and natural gas reserves are capitalized. Such capitalized costs include costs associated with lease acquisition, geological and geophysical work, delay rentals, drilling, completing and equipping oil and natural gas wells, and salaries, benefits and other internal salary related costs directly attributable to these activities. Proceeds from the disposition of oil and natural gas properties are generally accounted for as a reduction in capitalized costs, with no gain or loss recognized. Depletion of the capitalized costs of oil and natural gas properties, including estimated future development and capitalized asset retirement costs, is provided for using the equivalent unit-of-production method based upon estimates of proved oil and natural gas reserves on a quarterly basis. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. For example, a 10% reduction in our estimated reserves as of December 31, 2011 would have resulted in an increase of approximately $1.38 per BOE in our average 2011 depletion expense rate. Costs associated with production and general corporate activities are expensed in the period incurred. 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 are established or impairment is determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized, but are assessed, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under full cost accounting rules, capitalized costs of oil and natural gas properties, excluding costs associated with unproved properties, may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated twelve month arithmetic average of the prices in effect on the first day of each month of the relevant period and requires a write down for accounting purposes if the ceiling is exceeded.

Although we did not have ceiling test write downs during 2009, 2010 or 2011, we could be required to recognize impairments of oil and gas properties in future periods if market prices of oil and natural gas decline.

Asset Retirement Obligations

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

Income Tax Expense

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. We have recognized a valuation allowance against our net deferred taxes because we cannot conclude that it is more likely than not that the net deferred tax assets will be realized as a result of estimates of our future operating income based on current oil and natural gas commodity pricing. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, we consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. Future events or new evidence which may lead us to conclude that it is more likely than not that its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings; consistent and sustained pre-tax earnings; sustained or continued improvements in oil and natural gas commodity prices; consistent, meaningful production and proved reserves from our onshore Monterey shale project; and meaningful production and proved reserves from the CO2 project at the Hastings Complex. We will continue to evaluate whether the valuation allowance is needed in future reporting periods.

Derivative Instruments

We reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes, as well as utilizing a Black-Scholes option valuation model that is based upon underlying forward price curve data, risk-free interest rates, credit adjusted discount rates and estimated volatility factors. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity derivative 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. We do not apply hedge accounting to any of our derivative contracts, therefore we recognize mark-to-market gains and losses in earnings currently.

PV-10

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

	December 31,		
	2009(1)	**2010(2)**	**2011(3)**
Standardized measure of discounted future net cash flows	$692,805	$ 902,901	$1,364,146
Add: Present value of future income tax discounted at 10%	108,248	225,795	442,355
PV-10	$801,053	$1,128,696	$1,806,501

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $61.04 per Bbl for oil and natural gas liquids and $3.87 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at realized prices of $51.15 per Bbl for oil, $37.98 per Bbl for natural gas liquids and $3.80 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2009.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted in note (1) above to arrive at realized prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

(3) Unescalated twelve month arithmetic average of the first day of the month posted prices of $96.19 per Bbl for oil and natural gas liquids and $4.12 per MMBtu for natural gas were adjusted in note (1) above to arrive at realized prices of $99.62 per Bbl for oil, $68.40 per Bbl for natural gas liquids and $4.05 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2011.

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ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk

This section provides information about derivative financial instruments we use to manage commodity price volatility. Due to the historical volatility of crude oil and natural gas prices, we have implemented a hedging strategy aimed at reducing the variability of the prices we receive for our production and providing a minimum revenue stream. Currently, we purchase puts and enter into other derivative transactions such as collars and fixed price swaps in order to hedge our exposure to changes in commodity prices. All contracts are settled with cash and do not require the delivery of a physical quantity to satisfy settlement. While this hedging strategy may result in us having lower revenues than we would have if we were unhedged in times of higher oil and natural gas prices, management believes that the stabilization of prices and protection afforded us by providing a revenue floor on a portion of our production is beneficial. We may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of our existing positions. We may use the proceeds from such transactions to secure additional contracts for periods in which we believe there is additional unmitigated commodity price risk or for other corporate purposes.

This section also provides information about our interest rate risk. See "—Interest Rate Risk."

Commodity Derivative Transactions

Commodity Derivative Agreements. As of December 31, 2011, we had entered into various swap, collar and option agreements related to our oil and natural gas production. The aggregate economic effects of those agreements are summarized below. Location and quality differentials attributable to our 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 WTI (oil) or NYMEX Henry Hub (natural gas) price.

	Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Barrels/day	**Weighted Avg. Prices per Bbl**	**MMBtu/day**	**Weighted Avg. Prices per MMBtu**
January 1 - December 31, 2012:				
Collars(1)	6,500	$80.00/$118.15	13,400	$4.50/$5.25
Puts(1)	2,000	$60.00	37,300	$5.81
January 1 - December 31, 2013:				
Collars(1)	3,900	$81.79/$113.59	—	$—

(1) Reflects the impact of call spreads and purchased calls, which are transactions we entered into for the purpose of modifying or eliminating the ceiling (or call) portion of certain collar arrangements.

We have also entered into certain oil and natural gas basis swaps. The oil basis swaps fix the differential between the NYMEX WTI crude price index and the Brent crude price index. Historically the two price indexes have demonstrated a close correlation with each other and with the Southern California indexes on which we sell a significant percentage of our oil. Recently, however, the relationship between WTI and Brent has diverged, favoring Brent crude. The Southern California indexes most relevant to us have tracked more closely with Brent prices than with WTI. The oil basis swaps we have entered into attempt to fix the current premium Southern California indexes are realizing relative to WTI. The natural gas basis swaps fix the differential between the Henry Hub price and the PG&E Citygate price, the index on which the majority of our natural gas is sold. Our oil and natural gas basis swaps as of December 31, 2011 are presented below:

	Oil Basis Swaps (NYMEX WTI)			Natural Gas Basis Swaps (NYMEX Henry Hub)		
	Floating Index	Weighted Avg. Bbls/Day	Weighted Avg. Basis Differential to NYMEX WTI (per Bbl)	Floating Index	Weighted Avg. MMBtu/Day	Weighted Avg. Basis Differential to NYMEX HH (per MMBtu)
Basis Swaps:						
January 1 - December 31, 2012	Brent Crude	7,630	$ 6.90	PG&E Citygate	47,400	$ 0.28
January 1 - December 31, 2013	Brent Crude	3,900	$ 5.88	PG&E Citygate	12,000	$ 0.21

Portfolio of Derivative Transactions

Our portfolio of commodity derivative transactions as of December 31, 2011 is summarized below:

Oil

Type of Contract	Counterparty	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	RBS	NYMEX	3,000	$60.00/$121.10	Jan 1 - Dec 31, 12
Call (purchased)	Bank of Montreal	NYMEX	2,000	$121.10	Jan 1 - Dec 31, 12
Collar	Bank of Montreal	NYMEX	1,500	$80.00/$110.85	Jan 1 - Dec 31, 12
Collar	Bank of Montreal	NYMEX	1,000	$85.00/$120.30	Jan 1 - Dec 31, 12
Collar	Scotia Capital	NYMEX	1,000	$85.00/$120.10	Jan 1 - Dec 31, 12
Collar	BNP Paribas	NYMEX	2,000	$85.00/$120.10	Jan 1 - Dec 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	4,500	$7.28	Jan 1 - Mar 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	2,950	$7.28	Apr 1 - Dec 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	500	$7.15	Jan 1 - Mar 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	550	$7.15	Apr 1 - Dec 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	2,750	$6.90	Apr 1 - Dec 31, 12
Basis Swap	Bank of Montreal	NYMEX/Brent	2,250	$6.05	Apr 1 - Dec 31, 12
Collar	Credit Suisse	NYMEX	1,500	$80.00/$110.00	Jan 1 - Dec 31, 13
Collar	Credit Suisse	NYMEX	1,400	$85.00/$120.00	Jan 1 - Dec 31, 13
Collar	BNP Paribas	NYMEX	1,000	$80.00/$110.00	Jan 1 - Dec 31, 13
Basis Swap	Bank of Montreal	NYMEX/Brent	2,470	$6.05	Jan 1 - Dec 31, 13
Basis Swap	Bank of Montreal	NYMEX/Brent	1,000	$5.80	Jan 1 - Dec 31, 13
Basis Swap	Bank of Montreal	NYMEX/Brent	430	$5.10	Jan 1 - Dec 31, 13

Natural Gas

Type of Contract	Counterparty	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Collar	Credit Suisse	NYMEX	15,500	$6.00/$9.10	Jan 1 - Dec 31, 12
Call (purchased)	Credit Suisse	NYMEX	15,500	$9.10	Jan 1 - Dec 31, 12
Collar	Credit Suisse	NYMEX	14,000	$5.50/$8.00	Jan 1 - Dec 31, 12
Call (purchased)	Credit Suisse	NYMEX	14,000	$8.00	Jan 1 - Dec 31, 12
Collar	Scotia Capital	NYMEX	7,400	$4.50/$5.25	Jan 1 - Dec 31, 12
Collar	Key Bank	NYMEX	6,000	$4.50/$5.25	Jan 1 - Dec 31, 12
Put	RBS	NYMEX	7,800	$6.00	Jan 1 - Dec 31, 12
Basis Swap	Credit Suisse	PG&E Citygate	36,000	$0.275	Jan 1 - Dec 31, 12
Basis Swap	Key Bank	PG&E Citygate	11,400	$0.275	Jan 1 - Dec 31, 12
Basis Swap	Credit Suisse	PG&E Citygate	12,000	$0.21	Jan 1 - Dec 31, 13

Subsequent to December 31, 2011, we settled all of the natural gas derivative contracts that were outstanding at December 31, 2011 and realized a gain of $41.2 million. Additionally, we entered into the following commodity derivative contracts subsequent to December 31, 2011.

Natural Gas

Type of Contract	Counterparty	Basis	Quantity (MMBtu/d)	Strike Price ($/MMBtu)	Term
Swap	Credit Suisse	NYMEX	17,500	$3.00	Apr 1 - Dec 31, 12
Swap	Key Bank	NYMEX	12,000	$3.00	Apr 1 - Dec 31, 12
Collar	Key Bank	NYMEX	24,000	$3.50/$3.96	Jan 1 - Dec 31, 13
Collar	Credit Suisse	NYMEX	18,600	$3.75/$4.42	Jan 1 - Dec 31, 14
Collar	Scotia Capital	NYMEX	15,000	$3.75/$5.00	Jan 1 - Dec 31, 15

Oil

Type of Contract	Counterparty	Basis	Quantity (Bbl/d)	Strike Price ($/Bbl)	Term
Collar	Scotia Capital	ICE Brent	700	$90.00/$122.70	Jan 1 - Dec 31, 13

We enter into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. The objective of our hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. Our hedging activities seek to mitigate our exposure to price declines and allow us more flexibility to continue to execute our capital expenditure plan even if market prices decline. Our collar and swap contracts, however, prevent us from receiving the full advantage of increases in oil or natural gas prices above the maximum fixed amount specified in the hedge agreement. We do not enter into hedge positions for amounts greater than our expected production levels; however, if actual production is less than the amount we have hedged and the price of oil or natural gas exceeds a fixed price in a hedge contract, we will be required to make payments against which there are no offsetting sales of production. This could impact our liquidity and our ability to fund future capital expenditures. If we were unable to satisfy such a payment obligation, that default could result in a cross-default under our revolving credit agreement. In addition, we have incurred, and may incur in the future, substantial unrealized commodity derivative losses in connection with our hedging activities, although we do not expect such losses to have a material effect on our liquidity or our ability to fund expected capital expenditures.

In addition, the use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. We generally have netting arrangements with our counterparties that provide for the offset of payables against receivables from separate derivative arrangements with that counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. All of the counterparties to our derivative contracts are also lenders, or affiliates of lenders, under our revolving credit facility. Collateral under the revolving credit facility supports our collateral obligations under our derivative contracts. Therefore, we are not required to post additional collateral when we are in a derivative liability position. Our revolving credit facility and our derivative contracts contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

We have elected not to apply hedge accounting to any of our derivative transactions and consequently, we recognize mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges.

All derivative instruments are recorded on the balance sheet at fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date. Changes in the fair value of derivatives are recorded in commodity derivative (gains) losses on the consolidated statement of operations. As of December 31, 2011, the fair value of our commodity derivatives was a net asset of $48.2 million.

Interest Rate Risk

We are subject to interest rate risk with respect to amounts borrowed from time to time under our revolving credit facility because those amounts bear interest at variable rates. The interest rates associated with our senior notes are fixed for the term of the notes. A 1.0% increase in interest rates would have resulted in additional annualized interest expense of $0.4 million on our variable rate borrowings of $43.0 million related to our revolving credit facility as of December 31, 2011.

See notes to our consolidated financial statements for a discussion of our long-term debt as of December 31, 2011.

ITEM 8. Financial Statements and Supplementary Data

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

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

None.

ITEM 9A. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2011. This evaluation was conducted under the supervision and with the participation of management, including our CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that, as of December 31, 2011, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company,

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed our internal control over financial reporting as of December 31, 2011, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment, management has concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by Ernst & Young LLP, our independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2012 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 2012 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 2012 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 2012 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 2012 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 January 16, 2012, by and among Venoco, Inc., Denver Parent Corporation, Denver Merger Sub Corporation, and Timothy M. Marquez (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Venoco, Inc. filed on January 17, 2012).
2.2	Voting Agreement, dated as of January 16, 2012, by and among the Marquez Trust, the Marquez Foundation and Venoco, Inc. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K of Venoco, Inc. filed on January 17, 2012).
3.1	Restated Certificate of Incorporation of Venoco, Inc. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
3.2	Amended and Restated Bylaws of Venoco, Inc. (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K of Venoco, Inc. filed on September 5, 2008).

Exhibit Number	Exhibit
4.1	Indenture, dated as of October 7, 2009, by and among Venoco, Inc., the Guarantors named therein and U.S. Bank Trust National Association, as Trustee, relating to the 11.50% Senior Notes due 2017 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 7, 2009).
4.2	Indenture, dated as of February 15, 2011, by and among Venoco, Inc., the Guarantors named therein and U.S. Bank Trust National Association, as Trustee, relating to the 8.875% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K of Venoco, Inc. filed on February 16, 2011).
10.1	Fourth Amended and Restated Credit Agreement, dated as of April 15, 2011, by and among Venoco, Inc., the Guarantors identified therein, the Lenders party thereto, Bank of Montreal, as Administrative Agent, BMO Capital Markets, as Lead Arranger, The Bank of Nova Scotia and The Royal Bank of Scotland PLC, as Co-Syndication Agents and Key Bank National Association and Union Bank, N.A., as Co-Documentation Agents. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on April 18, 2011).
10.2	Option Agreement, dated as of November 1, 2006, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on November 9, 2006).
10.2.1	First Amendment to Option Agreement, by and between TexCal Energy South Texas, L.P. and Denbury Onshore, LLC, dated as of August 29, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on September 2, 2008).
10.3	Venoco, Inc. 2008 Employee Stock Purchase Plan, dated as of November 18, 2008, as amended as of December 31, 2008 (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 5, 2009).
10.4	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).
10.4.1	Amendment No. 1 to the Venoco, Inc. 2000 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.4.2	Form of Non-Qualified Stock Option Agreement for Non-Employee Directors Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.4.3	Form of Non-Qualified Stock Option Agreement for Non-Executive Officer Employees Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on November 17, 2005).
10.4.4	Form of Amendment to Nonqualified Stock Option Agreement Pursuant to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.4.5	Form of Bonus Payment Agreement Relating to the 2000 Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Venoco, Inc. filed on June 12, 2006).
10.5	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).

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Exhibit Number	Exhibit
10.5.1	Amendment No. 1 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 15, 2007).
10.5.2	Amendment No. 2 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan, dated as of November 17, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Venoco, Inc. filed on November 20, 2008).
10.5.3	Amendment No. 3 to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.7.3 to the Annual Report on Form 10-K of Venoco, Inc. filed on February 25, 2010).
10.5.4	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).
10.5.5	Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan and Stock Award Agreement, as amended (incorporated by reference to Exhibit 10.8.4 to the Annual Report on Form 10-K of Venoco, Inc. filed on March 5, 2009).
10.5.6	2010 Form of Notice of Stock Award Pursuant to the Venoco, Inc. Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.7.6 to the Annual Report on Form 10-K of Venoco, Inc. filed on February 25, 2010).
10.5.7	Venoco, Inc. Revised 2007 Long-Term Incentive Program. (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 5, 2011).
10.6	Venoco, Inc. 2007 Senior Executive Bonus Plan, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q of Venoco, Inc. filed on May 12, 2008).
10.7	Employment Agreement, dated as of March 1, 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).
10.8.1	Employment Agreement, dated as of March 1, 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).
10.8.2	Non-Qualified Stock Option Agreement, dated as of March 1, 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).
10.9	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).
10.10	Employment Agreement, dated as of March 19, 2007, by and between Venoco, Inc. and Timothy A. Ficker (incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 2, 2007).
10.11	Employment Agreement, dated January 16, 2012, by and between Ed O'Donnell and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on January 18, 2012).
10.12	Employment Agreement, dated January 15, 2012, by and between Mark DePuy and Venoco, Inc.

Exhibit Number	Exhibit
10.13	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).
10.14	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).
10.14.1	Amendment to Registration Rights Agreement and Joinder, dated as of May 23, 2007, by and among Venoco, Inc., the Marquez Trust and the Marquez Foundation (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on May 25, 2007).
10.15	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 10.29 to the Annual Report on Form 10-K of Venoco, Inc. filed on April 5, 2006).
10.16	Purchase and Sale Agreement, dated as of December 23, 2008, by and between Carpinteria Bluffs, LLC and Venoco, Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on December 29, 2008).
10.17	Sales Agency Agreement, dated October 12, 2010 by and between Venoco, Inc. and BMO Capital Markets Corp. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K of Venoco, Inc. filed on October 12, 2010).
21.1	Subsidiaries of the Registrant.
23.1	Consent of Ernst & Young LLP.
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 Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of DeGolyer & MacNaughton Regarding the Registrant's Reserves as of December 31, 2011 and Addendum thereto.
99.2	Non-Exclusive Aircraft Sublease Agreement, dated as of July 1, 2011, by and between Venoco, Inc. and TimBer, LLC.
101	The following financial information from the annual report on Form 10-K of Venoco, Inc. for the year ended December 31, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Changes in Stockholders' Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.

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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: February 15, 2012

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)	February 15, 2012
/s/ TIMOTHY A. FICKER Timothy A. Ficker	Chief Financial Officer (Principal Financial Officer)	February 15, 2012
/s/ DOUGLAS J. GRIGGS Douglas J. Griggs	Chief Accounting Officer (Principal Accounting Officer)	February 15, 2012
/s/ DONNA L. LUCAS Donna L. Lucas	Director	February 15, 2012
/s/ J. C. MCFARLAND J. C. McFarland	Director	February 15, 2012
/s/ JOEL L. REED Joel L. Reed	Director	February 15, 2012
/s/ M. W. SCOGGINS M. W. Scoggins	Director	February 15, 2012
/s/ MARK A. SNELL Mark A. Snell	Director	February 15, 2012
/s/ RICHARD S. WALKER Richard S. Walker	Director	February 15, 2012

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT
REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Venoco, Inc. and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Venoco, Inc. and subsidiaries at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009 the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Venoco, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 15, 2012

**REPORT OF INDEPENDENT
REGISTERED PUBLIC ACCOUNTING FIRM**

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

We have audited Venoco, Inc. and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Venoco, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Venoco, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Venoco, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 15, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 15, 2012

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VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(In thousands, except shares amounts)

	December 31, 2010	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,024	$ 8,165
Accounts receivable	29,602	30,017
Inventories	6,229	7,411
Other current assets	4,585	4,296
Income tax receivable	931	—
Commodity derivatives	26,407	47,768
Total current assets	72,778	97,657
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Oil and gas properties, full cost method of accounting		
Proved	1,734,190	1,971,499
Unproved	42,686	52,021
Accumulated depletion	(1,147,688)	(1,229,264)
Net oil and gas properties	629,188	794,256
Other property and equipment, net of accumulated depreciation and amortization of $16,588 and $16,176 at December 31, 2010 and December 2011, respectively	18,856	16,209
Net property, plant and equipment	648,044	810,465
OTHER ASSETS:		
Commodity derivatives	21,462	3,242
Deferred loan costs	6,096	15,320
Other	2,543	3,060
Total other assets	30,101	21,622
TOTAL ASSETS	$ 750,923	$ 929,744
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$ 45,396	$ 53,098
Interest payable	5,538	21,854
Commodity and interest derivatives	33,483	2,490
Total current liabilities	84,417	77,442
LONG-TERM DEBT	633,592	686,958
COMMODITY AND INTEREST DERIVATIVES	23,430	308
ASSET RETIREMENT OBLIGATIONS	93,721	92,008
Total liabilities	835,160	856,716
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value (200,000,000 shares authorized; 56,241,672 and 61,596,405 shares issued and outstanding at December 31, 2010 and 2011, respectively)	562	616
Additional paid-in capital	348,573	443,470
Retained earnings (accumulated deficit)	(433,372)	(371,058)
Total stockholders' equity	(84,237)	73,028
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 750,923	$ 929,744

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31,		
	2009	2010	2011
REVENUES:			
Oil and natural gas sales	$267,163	$290,608	$323,423
Other	3,331	4,684	5,355
Total revenues	270,494	295,292	328,778
EXPENSES:			
Lease operating expense	95,213	84,255	94,100
Production and property taxes	10,128	6,701	6,376
Transportation expense	3,163	9,102	9,348
Depletion, depreciation and amortization	86,226	78,504	85,817
Accretion of asset retirement obligations	5,765	6,241	6,423
General and administrative, net of amounts capitalized	36,939	37,554	39,186
Total expenses	237,434	222,357	241,250
Income (loss) from operations	33,060	72,935	87,528
FINANCING COSTS AND OTHER:			
Interest expense, net	40,984	40,584	61,113
Amortization of deferred loan costs	2,862	2,362	2,310
Interest rate derivative losses (gains), net	16,676	31,818	1,083
Loss on extinguishment of debt	8,493	—	1,357
Commodity derivative losses (gains), net	25,743	(68,049)	(40,649)
Total financing costs and other	94,758	6,715	25,214
Income (loss) before income taxes	(61,698)	66,220	62,314
INCOME TAXES:			
Current	(6,000)	(9,700)	—
Deferred	(8,400)	8,400	—
Income tax provision (benefit)	(14,400)	(1,300)	—
Net income (loss)	$ (47,298)	$ 67,520	$ 62,314
Earnings per common share:			
Basic	$ (0.93)	$ 1.23	$ 1.02
Diluted	$ (0.93)	$ 1.21	$ 1.02
Weighted average common shares outstanding:			
Basic	50,805	52,249	58,106
Diluted	50,805	53,018	58,236

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Years Ended December 31,		
	2009	**2010**	**2011**
Net income (loss)	$(47,298)	$67,520	$62,314
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:			
Hedging activities—Reclassification adjustments for settled contracts(1)	1,424	—	—
Other comprehensive income (loss)	1,424	—	—
Comprehensive income (loss)	$(45,874)	$67,520	$62,314

(1) Net of income tax expense (benefit) of $899, $0 and $0 for the years ended December 31, 2009, 2010 and 2011, respectively.

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
BALANCE AT DECEMBER 31, 2008	51,549	$ 515	$319,336	$(453,594)	$ (1,424)	$(135,167)
Comprehensive income:						
Reclassification adjustment for settled contracts, net of tax	—	—	899	—	1,424	2,323
Issuance of stock for cash upon exercise of options	66	1	680	—	—	681
Issuance of restricted shares, net of cancellations	835	8	(8)	—	—	—
Share-based compensation	—	—	4,590	—	—	4,590
Issuance of common stock pursuant to Employee Stock Purchase Plan	63	1	359	—	—	360
Disgorgement of stock sale profits	—	—	15	—	—	15
Net income (loss)	—	—	—	(47,298)	—	(47,298)
BALANCE AT DECEMBER 31, 2009	52,513	525	325,871	(500,892)	—	(174,496)
Issuance of stock for cash upon exercise of options	2,103	21	14,262	—	—	14,283
Issuance of restricted shares, net of cancellations	1,598	16	(16)	—	—	—
Share-based compensation	—	—	8,080	—	—	8,080
Issuance of common stock pursuant to Employee Stock Purchase Plan	28	—	376	—	—	376
Net income (loss)	—	—	—	67,520	—	67,520
BALANCE AT DECEMBER 31, 2010	56,242	562	348,573	(433,372)	—	(84,237)
Issuance of stock for cash upon exercise of options	186	2	1,654	—	—	1,656
Issuance of restricted shares, net of cancellations	542	5	(5)	—	—	—
Share-based compensation	—	—	10,800	—	—	10,800
Issuance of common stock pursuant to Employee Stock Purchase Plan	26	1	323	—	—	324
Issuance of stock, net of underwriters discounts	4,600	46	82,754	—	—	82,800
Stock issuance costs	—	—	(629)	—	—	(629)
Net income (loss)	—	—	—	62,314	—	62,314
BALANCE AT DECEMBER 31, 2011	61,596	$ 616	$443,470	$(371,058)	$ —	$ 73,028

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31,		
	2009	2010	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (47,298)	$ 67,520	$ 62,314
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	86,226	78,504	85,817
Accretion of asset retirement obligations	5,765	6,241	6,423
Deferred income tax provision (benefit)	(8,400)	8,400	—
Share-based compensation	2,824	5,653	6,747
Amortization of deferred loan costs	2,862	2,362	2,310
Loss on extinguishment of debt	8,493	—	1,357
Amortization of bond discounts and other	479	734	677
Unrealized interest rate swap derivative (gains) losses	(1,803)	13,724	(40,064)
Unrealized commodity derivative (gains) losses and amortization of premiums and other comprehensive loss	96,496	(14,548)	(9,993)
Changes in operating assets and liabilities:			
Accounts receivable	7,491	4,251	(415)
Inventories	(2,205)	(419)	(1,182)
Other current assets	81	(463)	112
Income tax receivable	(2,570)	2,185	931
Other assets	112	128	(517)
Accounts payable and accrued liabilities	(10,860)	(12,013)	18,178
Net premiums paid on derivative contracts	(19,002)	(1,586)	(7,199)
Net cash provided by operating activities	118,691	160,673	125,496
CASH FLOWS FROM INVESTING ACTIVITIES:			
Expenditures for oil and natural gas properties	(174,824)	(208,383)	(244,557)
Acquisitions of oil and natural gas properties	(22,794)	(4,112)	(253)
Expenditures for other property and equipment	(1,988)	(3,238)	(1,671)
Proceeds from sale of oil and natural gas properties	197,653	107,437	—
Net cash (used in) investing activities	(1,953)	(108,296)	(246,481)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term debt	276,562	135,000	588,000
Principal payments on long-term debt	(388,907)	(197,035)	(535,311)
Payments for deferred loan costs	(5,221)	(396)	(12,669)
Proceeds from issuance of common stock	—	—	82,800
Stock issuance costs	—	—	(629)
Proceeds from stock incentive plans and other	1,056	14,659	1,935
Net cash provided by (used in) financing activities	(116,510)	(47,772)	124,126
Net (decrease) increase in cash and cash equivalents	228	4,605	3,141
Cash and cash equivalents, beginning of period	191	419	5,024
Cash and cash equivalents, end of period	$ 419	$ 5,024	$ 8,165
Supplemental Disclosure of Cash Flow Information—			
Cash paid for interest	$ 40,990	$ 39,402	$ 44,130
Cash paid (received) for income taxes	$ (3,430)	$ (11,753)	$ (931)
Supplemental Disclosure of Noncash Activities—			
(Decrease) increase in accrued capital expenditures	$ (14,968)	$ 5,138	$ 5,840
Write off of deferred loan costs related to refinancing of notes	$ 1,866	$ —	$ 1,312

See notes to consolidated financial statements.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

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

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

Revenue Recognition and Gas Imbalances Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. This generally occurs when a barge completes delivery, oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under-deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over- and under- deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at December 31, 2010 and 2011.

Other revenues primarily include pipeline revenues, barge sub-charter revenues and other miscellaneous revenues.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

Accounts Receivable The components of accounts receivable include the following (in thousands):

	December 31,	
	2010	2011
Oil and natural gas sales related	$22,652	$26,498
Joint interest billings related	3,319	1,600
Other	4,431	2,719
Allowance for doubtful accounts	(800)	(800)
Total accounts receivable, net	$29,602	$30,017

The Company's accounts receivable result primarily from (i) oil and natural gas sales to oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are dispersed among various customers and purchasers and most of the Company's significant purchasers are large companies with solid credit ratings. If customers are considered a credit risk, letters of credit are the primary security obtained to support the extension of credit. For most joint working interest partners, the Company may have the right of offset against related oil and natural gas revenues. As of December 31, 2011, 63%, 18% and 3% of the total accounts receivable balance was receivable from the Company's three major customers.

The following table provides the percentage of revenue derived from oil and natural gas sales to customers who comprise 10% or more of the Company's annual revenue (the customers in each year are not necessarily the same from year to year):

	Years Ended December 31,		
	2009	2010	2011
Customer A	41%	57%	66%
Customer B	27%	26%	18%
Customer C	10%	—	—

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.

Accounting Pronouncements Regarding Oil and Natural Gas Resources In December 2008, the SEC published revised rules regarding oil and gas reserves reporting requirements. Key elements of the revised rules include a change in the pricing used to estimate reserves at period end, optional disclosure of probable and possible reserves and additional disclosure requirements. The rules also revised the prices used for reserves in determining depletion and the full cost ceiling test from a period end price to a twelve month average of the first day of the month prices.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

In January 2010, the Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") which amended existing oil and gas reserve accounting and disclosure guidance to align its requirements with the SEC's revised rules discussed above. In contrast to the SEC rule, the FASB does not permit the disclosure of probable and possible reserves in the supplemental oil and gas information in the notes to the financial statements. The revised SEC rules and the ASU amendments are effective for annual reporting periods ending on or after December 31, 2009. Application of the revised rules is prospective and companies are not required to change prior period presentation to conform to the amendments. Application of the amended guidance resulted in changes to the prices used to determine proved reserves at December 31, 2009 compared to prior periods, which did not result in significant changes to our oil and natural gas reserves.

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, 2009, 2010 and 2011 was $81.3 million, $74.1 million, and $81.6 million, respectively ($10.80, $11.13 and $12.69, respectively, per equivalent barrel of oil).

Unproved property costs not subject to amortization consist primarily of leasehold costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Costs of dry holes are transferred to the amortization base immediately upon determination that the well is unsuccessful. The Company will continue to evaluate these properties and costs which will be transferred into the amortization base as the undeveloped areas are tested. The Company transferred $9.7 million, $13.7 million, and $10.4 million of unproved costs into the amortization base in 2009, 2010 and 2011, respectively, due to impairment, development of acreage or placement of assets into service. No interest costs were capitalized in 2009, 2010 or 2011 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 Company did not record an impairment of oil and natural gas properties in 2009, 2010 or 2011, however, the Company could be required to recognize impairments of oil and natural gas properties in future periods if market prices of oil and natural gas decline.

General and Administrative Expenses Under the full cost method of accounting, the Company capitalizes a portion of general and administrative expenses that are directly identified with acquisition, exploration and development activities. These capitalized costs include salaries, employee benefits, costs

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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 $25.1 million, $22.7 million and $27.0 million directly related to its acquisition, exploration and development activities during 2009, 2010 and 2011, respectively.

Other Property and Equipment Other property and equipment, which includes buildings, drilling equipment, 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, 2009, 2010 and 2011 was $4.9 million, $4.4 million and $4.2 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. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are commercial banks that are parties to its revolving credit facility. The Company has elected not to apply hedge accounting to any of its derivative transactions and consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

Deferred Loan Costs Deferred loan costs, included in Other Assets, are amortized over the estimated lives of the related obligations using the effective interest method.

Asset Retirement Obligations The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time the well is spud or acquired.

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.

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

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The Company's policy is to recognize interest and/or penalties related to uncertain tax positions in interest expense.

Earnings Per Share Basic earnings (loss) per share is calculated by dividing net earnings (loss) attributable to common stock by the weighted average number of shares outstanding for the period (unvested restricted stock is excluded from the weighted average shares outstanding used in the basic earnings per share calculation). Under the treasury stock method, diluted earnings per share is calculated by dividing net earnings (loss) by the weighted average number of shares outstanding including all potentially dilutive common shares (unvested restricted stock and unexercised stock options). In the event of a net loss, no potential common shares are included in the calculation of shares outstanding, as their inclusion would be anti-dilutive.

Unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents are considered participating securities and are included in the computation of earnings per share pursuant to the two-class method. The Company's unvested restricted stock awards contain nonforfeitable dividend rights and participate equally with common stock with respect to dividends issued or declared. However, the Company's unvested restricted stock does not have a contractual obligation to share in losses of the Company. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, the two class method will not have an effect on the Company's basic earnings per share.

The following table details the weighted average dilutive and anti-dilutive securities, which consist of options and unvested restricted stock, for the periods presented (in thousands):

	Years Ended December 31,		
	2009	2010	2011
Dilutive	—	4,539	3,194
Anti-dilutive	4,914	474	502

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

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

	Years Ended December 31,		
	2009	2010	2011
Net income (loss)	$(47,298)	$67,520	$62,314
Allocation of net income to unvested restricted stock	—	(3,177)	(2,900)
Net earnings (loss) attributable to common stock	$(47,298)	$64,343	$59,414
Basic weighted average common shares outstanding	50,805	52,249	58,106
Add: dilutive effect of stock options	—	769	130
Diluted weighted average common shares outstanding	50,805	53,018	58,236
Basic earnings per common share	$ (0.93)	$ 1.23	$ 1.02
Diluted earnings per common share	$ (0.93)	$ 1.21	$ 1.02

Stock-Based Compensation Stock-based compensation is measured at the estimated grant date fair value of the awards and is recognized over the requisite service period (usually the vesting period). The Company estimates 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. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered. A market condition is not considered to be a vesting condition with respect to compensation expense. Therefore, an award is not deemed to be forfeited solely because a market condition is not satisfied.

Recently Issued Accounting Standards In May 2011, the FASB issued Accounting Standards Update No. 2011-04—*Fair Value Measurement—Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*, which amends current U.S. GAAP fair value measurement and disclosure guidance, to converge U.S. GAAP and IFRS requirements for measuring amounts at fair value as well as disclosures about these measurements. The authoritative guidance is effective for interim and annual periods beginning after December 15, 2011. The ASU is not expected to have a significant impact on the Company's financial statements, other than additional disclosures.

Recent Events—On August 26, 2011, the Company's board of directors received a proposal from its chairman and chief executive officer, Timothy Marquez, to acquire all of the outstanding shares of common stock of Venoco of which he is not the beneficial owner for $12.50 per share in cash. Mr. Marquez is the beneficial owner of approximately 50.3% of Venoco's common stock. The Company's board of directors formed a special committee comprised of all independent directors to evaluate and consider this proposal as well as third party alternatives. On January 16, 2012, the Company announced that it had entered into a definitive merger agreement with Mr. Marquez pursuant to which he will acquire all shares of which he is not the beneficial owner for $12.50 per share in cash. Completion of the transaction is subject to certain closing conditions, including procurement of financing, receipt of shareholder approval (including approval by a majority of the unaffiliated shareholders) and other customary conditions. As the transaction remains subject to certain closing conditions, there can be no assurance that it will be consummated.

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2. ACQUISITIONS AND SALES OF PROPERTIES

Sales of Texas Assets. In April 2010, the Company signed certain Purchase and Sale Agreements ("PSAs") to divest its producing properties in Texas ("Texas Sales") for $98.1 million (after closing adjustments and related expenses). The PSAs covered the Company's interests in the Manvel field, the Company's overriding royalty interest in the Hastings Complex and its other oil and natural gas producing properties in the Texas Gulf Coast. The sales closed in a series of transactions in the second quarter of 2010 and involved multiple purchasers, including Denbury Resources, Inc. ("Denbury"), which purchased the overriding royalty interest in the Hastings Complex. The Company used the proceeds from the sales to repay $66.9 million of the principal balance on the revolving credit facility and $30.7 million of the principal balance on the second lien term loan then in place. The Company did not recognize a gain or loss for financial reporting purposes on the sale in accordance with the full cost method of accounting, but recorded the proceeds from the Texas Sales as a reduction to the capitalized cost of its oil and natural gas properties. As a result of the Texas Sales, the Company no longer has any interests in producing oil and natural gas properties in Texas. The Company did, however, retain its 22.3% reversionary working interest in the Hastings Complex as described below.

Hastings Complex Sale. In February 2009, the Company completed the sale of its principal interests in the Hastings Complex to Denbury for approximately $197.7 million. As a result of the sale, the Company repaid all amounts then outstanding under the revolving credit facility and $5.5 million of the outstanding principal balance on the second lien term loan facility then in place. The proceeds from the Hastings Complex sale were applied as a reduction of capitalized costs of oil and natural gas properties.

As a result of the sale, Denbury committed to a development plan related to a CO_2 enhanced recovery project that requires it to make minimum capital expenditures in the amount of $178.7 million by the end of 2014. The Company retained an overriding royalty interest of 2.0% in the production from the properties, which, as described above, was subsequently sold to Denbury in the second quarter of 2010. In addition, the Company has the right to back-in to a working interest of approximately 22.3% in the Hastings Complex after Denbury recoups certain costs related to the CO_2 project.

3. LONG-TERM DEBT

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

	December 31,	
	2010	2011
Revolving credit agreement due March 2016	$ 35,000	$ 43,000
Second lien term loan due May 2014	455,311	—
11.50% senior notes due October 2017 (face value $150,000)	143,281	143,958
8.875% senior notes due February 2019 (face value $500,000)	—	500,000
Total long-term debt	633,592	686,958
Less: current portion of long-term debt	—	—
Long-term debt, net of current portion	$633,592	$686,958

3. LONG-TERM DEBT (Continued)

Revolving credit facility. In April 2011, the Company entered into a fourth amended and restated credit agreement which increased the size of its revolving credit facility from $300 million to $500 million. The facility has a maturity date of March 31, 2016. The borrowing base (currently established at $200 million) is subject to redetermination twice each year, and may be redetermined at other times at the Company's request or at the request of the lenders. The facility is secured by a first priority lien on substantially all of the Company's oil and natural gas properties and other assets, including the equity interests in all of the Company's subsidiaries, and is unconditionally guaranteed by each of the Company's subsidiaries other than Ellwood Pipeline, Inc. The collateral also secures the Company's obligations to hedging counterparties that are also lenders, or affiliates of lenders, under the facility. Loans made under the revolving credit facility are designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Loans designated as Base Rate Loans under the facility bear interest at a floating rate equal to (i) the greater of (x) the Bank of Montreal's announced base rate, (y) the overnight federal funds rate plus 0.50% and (z) the one-month LIBOR plus 1.0%, plus (ii) an applicable margin ranging from 0.75% to 1.75%, based on utilization. Loans designated as LIBO Rate Loans under the facility bear interest at (i) LIBOR plus (ii) an applicable margin ranging from 1.75% to 2.75%, based upon utilization. A commitment fee of 0.50% per annum is payable with respect to unused borrowing availability under the facility. The agreement governing the facility contains customary representations, warranties, events of default, indemnities and covenants, including operational covenants that restrict the Company's ability to incur indebtedness and financial covenants that require the Company to maintain specified ratios of current assets to current liabilities and debt to adjusted EBITDA.

The borrowing base under the revolving credit facility has been allocated at various percentages to a syndicate of 11 banks. Certain of the institutions included in the syndicate have received support from governmental agencies in connection with events in the credit markets.

As of February 14, 2012, the Company had $35.0 million outstanding on the facility and had available borrowing capacity of $161.2 million under the facility, net of the outstanding balance and $3.8 million in outstanding letters of credit.

Second lien term loan facility and 8.875% senior notes. In May 2007, the Company entered into a $500.0 million senior secured second lien term loan facility (the "second lien term loan facility"), which was due to mature on May 8, 2014. Prior to repayment of the second lien term loan facility in February 2011 (see below), loans made under the second lien term loan facility were designated, at the Company's option, as either "Base Rate Loans" or "LIBO Rate Loans." Loans designated as Base Rate Loans bore interest at a floating rate equal to (i) the greater of the overnight federal funds rate plus 0.50% and a market base rate, plus (ii) 3.00%. Loans designated as LIBO Rate Loans bore interest at LIBOR plus 4.00%.

In February 2011, the Company issued $500 million in 8.875% senior notes due in February 2019 at par. Concurrently with the sale of the 8.875% senior notes, the Company repaid in full the outstanding principal balance of $455.3 million on the second lien term loan, plus accrued interest of $1.6 million. The 8.875% senior notes pay interest semi-annually in arrears on February 15 and August 15 of each year. The Company may redeem the notes prior to February 15, 2015 at a "make whole premium" defined in the indenture. Beginning February 15, 2015, the Company may redeem the notes at a redemption price of 104.438% of the principal amount and declining to 100% by

3. LONG-TERM DEBT (Continued)

February 15, 2017. The 8.875% senior notes are senior unsecured obligations and contain operational covenants that, among other things, limit the Company's ability to make investments, incur additional indebtedness, issue preferred stock, pay dividends, repurchase its stock, create liens or sell assets.

The Company recorded a loss on extinguishment of debt of $1.4 million in connection with the repayment of the second lien term loan.

11.50% senior notes. In October 2009, the Company issued $150.0 million of 11.50% senior notes due October 2017 at a price of 95.03% of par. The senior notes pay interest semi-annually in arrears on April 1 and October 1 of each year. The Company may redeem the senior notes prior to October 1, 2013 at a "make-whole price" defined in the indenture. Beginning October 1, 2013, the Company may redeem the notes at a redemption price equal to 105.75% of the principal amount and declining to 100% by October 1, 2016. The 11.50% notes are senior unsecured obligations and contain covenants that, among other things, limit the Company's ability to make investments, incur additional debt, issue preferred stock, pay dividends, repurchase its stock, create liens or sell assets.

The Company was in compliance with all debt covenants at December 31, 2011.

Scheduled annual maturities of long-term debt outstanding as of December 31, 2011 were as follows (in thousands):

Year Ending December 31 (in thousands):	
2012	$ —
2013	—
2014	—
2015	—
2016	43,000
Thereafter	643,958
	$686,958

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Agreements. The Company utilizes swap and collar agreements and option contracts to hedge the effect of price changes on a portion of its future oil and natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements. The Company may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of the Company's existing positions. The Company may use the proceeds from such transactions to secure additional contracts for periods in which the Company believes it has additional unmitigated commodity price risk or for other corporate purposes.

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4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are with multiple counterparties to minimize exposure to any individual counterparty. The Company generally has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with that counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. All of the counterparties to the Company's derivative contracts are also lenders, or affiliates of lenders, under its revolving credit facility. Collateral under the revolving credit facility supports the Company's collateral obligations under the Company's derivative contracts. Therefore, the Company is not required to post additional collateral when the Company is in a derivative liability position. The Company's revolving credit facility and derivative contracts contain provisions that provide for cross defaults and acceleration of those debt and derivative instruments in certain situations.

The Company has elected not to apply hedge accounting to any of its derivative transactions and, consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges.

The Company has paid premiums related to certain of its outstanding derivative contracts. These premiums are amortized into commodity derivative (gains) losses over the period for which the contracts are effective. At December 31, 2011, the balance of unamortized net derivative premiums paid was $12.4 million, of which $11.4 million and $1.0 million will be amortized in 2012 and 2013, respectively.

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

	Years Ended December 31,		
	2009	2010	2011
Realized commodity derivative losses (gains)	$(68,429)	$(53,501)	$(30,656)
Amortization of commodity derivative premiums	22,661	24,808	10,058
Unrealized commodity derivative losses (gains) for changes in fair value	71,511	(39,356)	(20,051)
Commodity derivative losses (gains), net	$ 25,743	$(68,049)	$(40,649)

During the fourth quarter of 2011, the Company unwound its existing 2013 natural gas collars and puts and received $12.0 million. The gain recognized is included in realized commodity derivative losses (gains).

As of December 31, 2011, the Company had entered into swap, collar and option agreements related to its oil and natural gas production. The aggregate economic effects of those agreements are 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

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

differential between the agreement price and the actual NYMEX WTI ("WTI") (oil) or NYMEX Henry Hub (natural gas) price.

	Oil (NYMEX WTI)		Natural Gas (NYMEX Henry Hub)	
	Barrels/day	Weighted Avg. Prices per Bbl	MMBtu/day	Weighted Avg. Prices per MMBtu
January 1 - December 31, 2012:				
Collars(1)	6,500	$80.00/$118.15	13,400	$4.50/$5.25
Puts(1)	2,000	$60.00	37,300	$5.81
January 1 - December 31, 2013:				
Collars(1)	3,900	$81.79/$113.59	—	$—

(1) Reflects the impact of call spreads and purchased calls, which are transactions we entered into for the purpose of modifying or eliminating the ceiling (or call) portion of certain collar arrangements.

The Company has also entered into certain oil and natural gas basis swaps. The oil basis swaps fix the differential between the WTI crude price index and the Inter-Continental Exchange Brent crude price index ("Brent"). Historically the two price indexes have demonstrated a close correlation with each other and with the Southern California indexes on which the Company sells a significant percentage of its oil. Recently, however, the relationship between WTI and Brent has diverged, favoring Brent crude. The Southern California indexes most relevant to the Company have tracked more closely with Brent prices than to WTI. The oil basis swaps the Company has entered into attempt to fix the current premium Southern California indexes are realizing relative with WTI. The natural gas basis swaps fix the differential between the Henry Hub price and the PG&E Citygate price, the index on which the majority of the Company's natural gas is sold. The Company's oil and natural gas basis swaps as of December 31, 2011 are presented below:

	Oil Basis Swaps (NYMEX WTI)			Natural Gas Basis Swaps (NYMEX Henry Hub)		
	Floating Index	Weighted Avg. Bbls/Day	Weighted Avg. Basis Differential to NYMEX WTI (per Bbl)	Floating Index	Weighted Avg. MMBtu/Day	Weighted Avg. Basis Differential to NYMEX HH (per MMBtu)
Basis Swaps:						
January 1 - December 31, 2012	Brent Crude	7,630	$ 6.90	PG&E Citygate	47,400	$ 0.28
January 1 - December 31, 2013	Brent Crude	3,900	$ 5.88	PG&E Citygate	12,000	$ 0.21

Subsequent to December 31, 2011, the Company unwound all of its 2012 natural gas collars and puts and its 2012 and 2013 natural gas basis swaps, for which it received $41.2 million. The Company also entered into the following commodity derivative contracts subsequent to December 31, 2011:

- Natural gas swaps at $3.00 (NYMEX) on 29,500 MMBtu per day, effective April 1 through December 31, 2012
- Natural gas collar at $3.50/$3.96 (NYMEX) on 24,000 MMBtu per day, effective calendar 2013

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

- Natural gas collar at $3.75/$4.42 (NYMEX) on 18,600 MMBtu per day, effective calendar 2014
- Natural gas collar at $3.75/$5.00 (NYMEX) on 15,000 MMBtu per day, effective calendar 2015
- Oil collar at $90.00/$122.70 (Brent) on 700 Bbls per day, effective calendar 2013

Interest Rate Swap. The Company previously entered into interest rate swap transactions to lock in its interest cost on $500.0 million of variable rate borrowings through May 2014. Under the swap arrangements, the Company paid a fixed interest rate of 3.840% and received a floating interest rate based on the one-month LIBO rate, with settlements made monthly. As a result of the interest rate swap agreement, $500 million of the Company's variable rate debt effectively bore interest at a fixed rate of approximately 7.8%. The Company did not designate the interest rate swap as a hedge.

In February 2011, the Company repaid the principal balance outstanding on the second lien term loan from proceeds received from the issuance of the 8.875% senior notes (see note 3), which reduced the Company's debt subject to variable rate interest to any amounts which may be outstanding under the Company's revolving credit facility. As a result, the Company settled the interest rate swaps for $38.1 million in February 2011.

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

	Years Ended December 31,		
	2009	2010	2011
Realized interest rate derivative losses (gains)	$18,479	$18,094	$ 41,147
Unrealized interest rate derivative losses (gains)	(1,803)	13,724	(40,064)
Interest rate derivative losses (gains), net	$16,676	$31,818	$ 1,083

Fair Value of Derivative Instruments. The estimated fair values of derivatives included in the consolidated balance sheets at December 31, 2010 and 2011 are summarized below. The net fair value of the Company's derivatives changed by $57.2 million from a net liability of $9.0 million at December 31, 2010 to a net asset of $48.2 million at December 31, 2011, primarily due (i) settlement of the interest rate swaps in February 2011, (ii) changes in the futures prices for oil and natural gas, which are used in the calculation of the fair value of commodity derivatives, (iii) settlement of commodity derivative positions during the current period and (iv) changes to the Company's commodity derivative portfolio during 2011. The Company does not offset asset and liability positions with the same counterparties within the financial statements, rather, all contracts are presented at their gross estimated fair value. As of the dates indicated, the Company's derivative assets and liabilities are presented below (in thousands). These balances represent the estimated fair value of the contracts. The

4. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

Company has not designated any of its derivative contracts as hedging instruments. The main headings represent the balance sheet captions for the contracts presented.

	December 31,	
	2010	2011
Current Assets—Commodity derivatives:		
Oil derivative contracts	$ 95	$ 6,190
Gas derivative contracts	26,312	41,578
	26,407	47,768
Other Assets—Commodity derivatives:		
Oil derivative contracts	—	3,230
Gas derivative contracts	21,462	12
	21,462	3,242
Current Liabilities—Commodity and interest derivatives:		
Oil derivative contracts	(8,039)	(2,490)
Gas derivative contracts	(6,890)	—
Interest rate derivative contracts	(18,554)	—
	(33,483)	(2,490)
Commodity and interest derivatives:		
Oil derivative contracts	(1,921)	(308)
Gas derivative contracts	—	—
Interest rate derivative contracts	(21,509)	—
	(23,430)	(308)
Net derivative asset (liability)	$ (9,044)	$48,212

5. FAIR VALUE MEASUREMENTS

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

The three levels of the fair value hierarchy are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

5. FAIR VALUE MEASUREMENTS (Continued)

Level 2—Pricing inputs are other than quoted prices in active markets included in level 1, but are either directly or indirectly observable as of the reported date and for substantially the full term of the instrument. Inputs may include quoted prices for similar assets and liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2011 (in thousands).

	Level 1	Level 2	Level 3	Fair Value as of December 31, 2011
Assets (Liabilities):				
Commodity derivative contracts	$ —	$51,010	$ —	$ 51,010
Commodity derivative contracts	—	(2,798)	—	(2,798)

The Company's commodity derivative instruments consist primarily of swaps, collars and option contracts for oil and natural gas. The Company values the derivative contracts using industry standard models, based on an income approach, which considers various assumptions including quoted forward prices and contractual prices for the underlying commodities, time value and volatility factors, as well as other relevant economic measures. Substantially all of the assumptions can be observed throughout the full term of the contracts, can be derived from observable data or are supportable by observable levels at which transactions are executed in the marketplace and are therefore designated as level 2 within the fair value hierarchy. The discount rates used in the assumptions include a component of non-performance risk. The Company utilizes the relevant counterparty valuations to assess the reasonableness of the calculated fair values.

Fair Value of Financial Instruments. The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, derivatives (discussed above) and long-term debt. The carrying values of cash equivalents and accounts receivable and payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's revolving credit facility approximated fair value because the interest rate of the facility is variable. The fair value of the second lien term loan facility and the senior notes listed in the tables below were derived from available market data. This disclosure does not impact our financial position, results of operations or cash flows (in thousands).

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5. FAIR VALUE MEASUREMENTS (Continued)

	December 31, 2010		December 31, 2011	
	Carrying Value	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Revolving credit agreement	$ 35,000	$ 35,000	$ 43,000	$ 43,000
Second lien term loan	455,311	434,253	—	—
11.50% senior notes	143,281	162,000	143,958	154,500
8.875% senior notes	—	—	500,000	455,000

6. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in properties (including removal of certain onshore and offshore facilities) at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its asset retirement obligations when incurred by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted as a component of the full cost pool using the units-of-production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended December 31, 2010 and 2011 (in thousands):

	2010	2011
Asset retirement obligations at beginning of period	$92,985	$ 94,221
Revisions of estimated liabilities	(3,016)	(13,353)
Liabilities incurred or acquired	5,552	5,556
Liabilities settled	(1,078)	(339)
Disposition of properties	(6,463)	—
Accretion expense	6,241	6,423
Asset retirement obligations at end of period	94,221	92,508
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	(500)	(500)
Long-term asset retirement obligations	$93,721	$ 92,008

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 4% and 9%. The revisions of $13.4 million for 2011 primarily relate to updated estimated useful lives of certain of the Company's offshore platforms and support facilities. In particular, reserve lives for the South Ellwood field were extended in connection with the approval of the common carrier pipeline that transports oil from the field to refiners and replaced the use of a barge. The 2010 revisions primarily relate to updated estimates for expected cash outflows and changes in the timing of obligations.

7. INCOME TAXES

The Company accounts for income taxes under the asset and liability approach, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's consolidated financial statements or tax returns.

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

	Years Ended December 31,		
	2009	2010	2011
Current:			
Federal	$ (3,550)	$ (9,400)	$ —
State	(2,450)	(300)	—
	(6,000)	(9,700)	—
Deferred:			
Federal	(8,400)	8,400	—
State	—	—	—
	(8,400)	8,400	—
Total income tax provision (benefit)	$ (14,400)	$ (1,300)	$ —

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

	Years Ended December 31,		
	2009	2010	2011
Income tax expense (benefit) at federal statutory rate	$ (21,594)	$ 23,177	$ 21,810
State income taxes	(1,864)	2,328	2,392
Other	2,103	(286)	(1,200)
Valuation allowance	6,955	(26,519)	(23,002)
	$ (14,400)	$ (1,300)	$ —

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

7. INCOME TAXES (Continued)

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

	December 31,	
	2010	2011
Deferred income tax assets:		
Oil and gas properties	$ 50,978	$ 11,401
Net operating losses	66,459	101,939
Unrealized interest rate swap losses	15,431	—
Bad debts	132	132
Accrued liabilities	1,297	1,957
Share-based compensation	—	970
Charitable contributions	2,053	2,547
State tax benefit	171	169
Alternative minimum tax credits	9,901	10,585
Valuation allowance	(137,381)	(114,379)
	9,041	15,321
Deferred income tax liabilities:		
Unrealized commodity derivative gains	(6,116)	(13,955)
Share-based compensation	(1,607)	—
Prepaid expenses	(1,318)	(1,366)
	(9,041)	(15,321)
Net deferred income tax assets (liabilities)	—	—
Net current deferred tax asset	—	—
Noncurrent deferred tax asset	$ —	$ —

The Company has net operating loss carryovers as of December 31, 2011 of $295.7 million for federal income tax purposes and $265.0 million for financial reporting purposes. The difference of $30.7 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset taxable income through 2031.

The Company incurred losses before income taxes in 2008 and 2009 as well as taxable losses in each of the tax years from 2008 through 2011. These losses and expected future taxable losses were a key consideration that led the Company to provide a valuation allowance against its net deferred tax assets of $114.4 million as of December 31, 2011, since it cannot conclude that it is more likely than not that $114.4 million of the net deferred tax assets will be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At each reporting period, management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, tax planning strategies and projected future taxable income in making this assessment. Future events or new evidence which may lead the Company to conclude that it is more likely than not that its net deferred tax assets will be realized include, but are not limited to, cumulative historical pre-tax earnings; consistent and sustained pre-tax earnings; sustained or continued improvements in oil and natural gas commodity prices; consistent, meaningful production and proved

7. INCOME TAXES (Continued)

reserves from the Company's onshore Monterey shale project; and meaningful production and proved reserves from the CO2 project at the Hastings Complex. The Company will continue to evaluate whether the valuation allowance is needed in future reporting periods.

As long as the Company concludes that it will continue to have a need for a full valuation allowance against its net deferred tax assets, the Company likely will not have any income tax expense or benefit other than for federal alternative minimum tax expense, a release of a portion of the valuation allowance for net operating loss carryback claims or for state income taxes.

The Company's federal income tax returns for the 2003 through 2008 tax years have been examined by the U.S. Internal Revenue Service ("IRS") with minimal disallowed deductions resulting from the examinations. As part of that process with the IRS, the Company carried back net operating losses ("NOL") to tax years 2003 through 2005, which resulted in federal tax refunds of $8.6 million. The 2009 through 2011 tax years remain open to examination by the IRS.

During the third quarter of 2010, the California Franchise Tax Board ("FTB") completed an examination of the Company's 2003 and 2004 California income tax returns. No adjustments resulted from this examination other than adjustments related to the finalization of the federal examinations discussed above, which the Company had previously provided for in its liability for uncertain state tax positions. The 2007 through 2011 tax years remain open to examination by the various state jurisdictions.

Due to the finalization of the 2003 through 2008 IRS examinations, the NOL carryback claims filed with the IRS and the finalization of the 2003 and 2004 FTB examinations, the Company believes that it has no liability for uncertain tax positions.

8. CAPITAL STOCK

The Company had 65.6 million shares of common stock issued or reserved for issuance at December 31, 2011. At December 31, 2011, the Company had 61.6 million common shares issued and outstanding, of which 2.8 million shares are restricted stock granted under the Company's 2005 stock incentive plan. At December 31, 2011, the Company had approximately 0.8 million options outstanding and 2.8 million shares available to be issued pursuant to awards under its stock incentive plans, including the 2008 Employee Stock Purchase Plan.

During the first quarter of 2011, the Company sold 4.6 million shares of common stock in a public offering at $18.75 per share and received approximately $82.2 million in net proceeds, after underwriting discounts and estimated expenses.

9. SHARE-BASED PAYMENTS

The Company has granted options to directors, certain employees and officers of the Company other than its CEO, under its 2000 and 2005 Stock Plans (the "Stock Plans"). As of December 31, 2011, there are a total of 846,055 options outstanding with a weighted average exercise price of $13.53 ($6.00 to $20.00), all of which have vested. The options typically have a maximum life of 10 years.

As of December 31, 2011, there were a total of 2,815,244 shares of restricted stock outstanding under the Company's 2005 stock incentive plan, including 1,070,495 shares granted to its CEO. Restricted shares subject to service conditions only generally vest over a four year period, with 25% vesting on each subsequent anniversary of the grant date. The grant date fair value of restricted stock subject to service conditions only is determined by the Company's closing stock price on the day prior

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9. SHARE-BASED PAYMENTS (Continued)

to the date of grant. The vesting of 1,845,147 shares is also subject to market conditions based on the Company's total shareholder return in comparison to peer group companies and/or an industry index for each calendar year. Shares of restricted stock subject to market conditions granted prior to 2011 have a four year period over which vesting may occur. For grants issued in 2011, this period was expanded by three years in which a portion of the available shares could vest. The weighted-average fair value of the restricted shares subject to market conditions was derived using a Monte Carlo technique. The weighted average fair value of 496,846 awards with market conditions granted in February 2011 was estimated to be $17.83 per share. The estimated grant date fair values of restricted share awards are recognized as expense over the requisite service periods. The Company's total shareholder return for the measurement period of December 31, 2010 through December 31, 2011 was below the minimum threshold, therefore, none of the market based restricted shares will vest for this measurement period.

As of December 31, 2011, there was $16.8 million of total unrecognized compensation cost related to restricted stock, which is expected to be amortized over a weighted average period of 2.6 years. All compensation cost related to stock options has been recognized.

The Company recognized total share-based compensation costs as follows (in thousands):

	Years Ended December 31,		
	2009	2010	2011
General and administrative expense	$ 3,890	$ 6,930	$ 9,720
Oil and natural gas production expense	700	1,150	1,080
Total share-based compensation costs	4,590	8,080	10,800
Less: share-based compensation costs capitalized	(1,766)	(2,427)	(4,053)
Share-based compensation expensed	$ 2,824	$ 5,653	$ 6,747

The following summarizes the Company's stock option activity for the years ended December 31, 2009, 2010 and 2011:

	Years Ended December 31,						
	2009		2010		2011		
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value of Options(1) (in thousands)
Outstanding, start of period	3,504,263	$ 9.16	3,301,903	$ 8.92	1,093,758	$ 13.07	
Granted	—	—	—	—	—	—	
Exercised	(66,560)	$ 10.23	(2,103,195)	$ 6.79	(185,753)	$ 9.69	
Cancelled	(135,800)	$ 11.46	(104,950)	$ 8.50	(61,950)	$ 19.26	
Outstanding, end of period	3,301,903	$ 8.92	1,093,758	$ 13.07	846,055	$ 13.53	$ 60
Exercisable, end of period	3,128,153	$ 8.50	1,045,258	$ 12.90	846,055	$ 13.53	$ 60

(1) The intrinsic value is the amount by which the market value of the underlying stock, as of the date outstanding, exceeds the exercise price of in-the-money options.

9. SHARE-BASED PAYMENTS (Continued)

Additional information related to options outstanding at December 31, 2011 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	77,500	3.2	$ 6.00	77,500	3.2	$ 6.00
$8.00–$8.68	137,275	3.3	$ 8.00	137,275	3.3	$ 8.00
$10.67–$14.97	235,000	4.4	$ 12.72	235,000	4.4	$ 12.72
$15.00–$20.00	396,280	5.1	$ 17.39	396,280	5.1	$ 17.39
	846,055	4.4	$ 13.53	846,055	4.4	$ 13.53

The aggregate intrinsic value of options exercised in 2009, 2010 and 2011 was $0.2 million, $23.3 million and $2.2 million, respectively.

The Company had 48,500 unvested option awards outstanding on January 1, 2011 with a weighted average grant date fair value of $7.48 per award, all of which vested during the year.

The following summarizes the Company's unvested restricted stock award activity for the years ended December 31, 2009, 2010 and 2011.

	Years Ended December 31,					
	2009		2010		2011	
Non-vested restricted stock	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted-Average Grant-Date Fair Value	Shares	Weighted Average Grant Date Fair Value
Non-vested, start of period	851,545	$ 12.65	1,594,156	$ 7.20	2,603,250	$ 9.70
Granted	895,376	$ 2.94	1,860,435	$ 11.81	793,831	$ 17.01
Vested	(92,410)	$ 13.82	(589,134)	$ 9.10	(330,480)	$ 10.85
Forfeited	(60,355)	$ 10.86	(262,207)	$ 10.75	(251,357)	$ 12.83
Non-vested, end of period	1,594,156	$ 7.20	2,603,250	$ 9.70	2,815,244	$ 11.35

The Company also provides a non-compensatory Employee Stock Purchase Plan (the "ESPP"), for which 1.4 million authorized shares of common stock remain available for issuance. Participation in the ESPP is open to all employees, other than executive officers, who meet limited qualifications. Under the terms of the ESPP, employees are able to purchase Company stock at a 5% discount as determined by the fair market value of the Company's stock on the last trading day of each purchase period. Individual employees are limited to $25,000 of common stock purchased in any calendar year.

10. RELATED PARTY TRANSACTIONS

In 2006, the Company paid a dividend consisting of 100% of its membership interest in 6267 Carpinteria Avenue, LLC ("6267 Carpinteria") to its then sole stockholder, a trust controlled by the Company's Chief Executive Officer. 6267 Carpinteria owns the office building and related land used by the Company in Carpinteria, California. The Company makes lease payments to 6267 Carpinteria under a lease for the office building entered into prior to the dividend. The lease provides for minimum lease payments of approximately $1.2 million per year through 2019.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

10. RELATED PARTY TRANSACTIONS (Continued)

The Company has entered into a non-exclusive aircraft sublease agreement with TimBer, LLC, a company owned by the Company's Chief Executive Officer, Timothy Marquez, and his wife. Through December 31, 2011, the Company has incurred approximately $1.2 million of costs related to the agreement, of which $1.1 million remains in accounts payable and accrued liabilities on the Company's balance sheet at December 31, 2011.

11. COMMITMENTS

Leases—The Company has entered into lease agreements for office space, an office building, and a parcel of land adjacent to Ellwood pier used for pier access. As of December 31, 2011, future minimum lease payments under operating leases that have initial or remaining non-cancelable terms in excess of one year are $2.7 million in 2012, $2.9 million in 2013, $2.1 million in 2014, $1.9 million in 2015, $2.0 million in 2016 and $6.4 million thereafter. Net rent expense incurred for office space and the office building was $3.8 million, $2.5 million and $2.3 million in 2009, 2010 and 2011, respectively.

12. CONTINGENCIES

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 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. The Company has owned an oil and natural gas facility adjacent to the school since 1995. For the majority of the plaintiffs, their alleged exposures occurred before the Company acquired the facility. All cases were consolidated before one judge. Twelve "representative" plaintiffs were selected to have their cases tried first, while all of the other plaintiffs' cases were stayed. In November 2006, the judge entered summary judgment in favor of all defendants in the test cases, including the Company. The judge dismissed all claims by the test case plaintiffs on the ground that they offered no evidence of medical causation between the alleged emissions and the plaintiffs' alleged injuries. Plaintiffs appealed the ruling. A decision on the appeal is expected in 2012. The Company vigorously defended the actions, and will continue to do so until they are resolved. Certain defendants and related parties have made claims for indemnity which the Company is disputing. The Company cannot predict the cost of 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. If the insurer ceases to provide such defense 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 its policies applies, the Company will not have the protection of those policies with respect to any damages or settlement costs ultimately incurred in the lawsuits.

Based on the information known to the Company to date, the Company does not believe that it is probable that a material judgment against the Company will result. Therefore, no liability has been accrued. 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.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

12. CONTINGENCIES (Continued)

State Lands Commission Royalty Litigation

In November 2011, the California State Lands Commission (SLC) filed suit against the Company in Santa Barbara County alleging that the Company underpaid royalties on oil and gas produced from the South Ellwood field in California for the period from August 1, 1997 through May 2011 by approximately $9.5 million. The case has since been removed to Los Angeles County, California. The principal issues in dispute are (i) the oil price on which royalties should be calculated and (ii) whether the Company is entitled to deduct the cost of transporting oil from the South Ellwood Field to the point of sale in calculating the royalty. With respect to the oil price, the Company has paid royalties based on the price the Company actually received in arms-length transactions. The SLC contends that the Company should be paying royalties based on the higher of the price actually received and the highest "posted price" for oil sold in the Midway Sunset field, near Bakersfield, California. With respect to the deduction of transportation costs, the Company believes that state law allows the Company to adjust the sale price to reflect the cost of delivering the oil from the field to the point of sale. Based on its review of the SLC's contentions, audit records and additional historical records, the Company believes that it may have overpaid royalties on oil and gas production during the period in question and may be owed a refund of such overpayments. The Company believes the position of the SLC is without merit and the Company intends to vigorously contest the suit and to enforce its right to receive a refund of royalties it may have overpaid. The Company does not believe that it is probable that a material judgment against the Company will result. Therefore, no liability has been accrued.

Delaware Litigation

On August 26, 2011, Timothy Marquez, the Chairman and CEO of the Company, submitted a nonbinding proposal to the board of directors of the Company to acquire all of the shares of the Company he does not beneficially own for $12.50 per share in cash (the "Marquez Proposal"). As a result of that proposal, four lawsuits were filed in the Delaware Court of Chancery in 2011 against the Company and each of its directors by shareholders alleging that the Company and its directors had breached their fiduciary duties to the shareholders in connection with the Marquez Proposal. A fifth lawsuit filed in 2011, also in the Delaware Court of Chancery, named only Mr. Marquez as a defendant. On January 16, 2012, the Company announced it had entered into a merger agreement with Mr. Marquez and certain of his affiliates pursuant to which, at closing, each of the shareholders other than Mr. Marquez and his affiliates would receive $12.50 for each share of Company stock (the "Merger"). Following announcement of the merger agreement, three additional suits were filed in Delaware and three suits were filed in federal court in Colorado naming as defendants the Company and each of its directors. Each action seeks certification as a class action. Plaintiffs in both the Delaware and Colorado actions challenge the Merger and allege, among other things, that the consideration to be paid is inadequate. The complaints seek, among other relief, to enjoin defendants from consummating the Merger and to direct defendants to exercise their fiduciary duties to obtain a transaction that is in the best interests of the shareholders. The Company has reviewed the allegations contained in the complaints and believes they are without merit.

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

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13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2010 and 2011 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Year Ended December 31, 2010:				
Revenues	$ 82,756	$70,058	$ 70,412	$ 72,066
Income (loss) from operations	27,638	12,402	15,956	16,939
Net income (loss)	43,988	3,709	15,388	4,435
Basic earnings per common share	$ 0.83	$ 0.07	$ 0.28	$ 0.08
Diluted earnings per common share	$ 0.81	$ 0.07	$ 0.28	$ 0.08

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Year Ended December 31, 2011:				
Revenues	$ 79,190	$87,289	$ 78,931	$ 83,368
Income (loss) from operations	20,870	30,035	14,819	21,804
Net income (loss)	(23,925)	19,023	36,794	30,422
Basic earnings per common share	$ (0.43)	$ 0.31	$ 0.60	$ 0.49
Diluted earnings per common share	$ (0.43)	$ 0.31	$ 0.60	$ 0.49

14. 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 the FASB guidance regarding Oil and Gas Reserve Estimation and Disclosures. At December 31, 2011, 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, 2009, 2010 and 2011 were prepared by DeGolyer and MacNaughton, independent petroleum reserve engineers.

Capitalized Costs of Oil and Natural Gas Properties

	As of December 31,		
	2009	2010	2011
		(in thousands)	
Unevaluated properties(1)	$ 31,934	$ 42,686	$ 52,021
Properties subject to amortization	1,640,967	1,734,190	1,971,499
Total capitalized costs	1,672,901	1,776,876	2,023,520
Accumulated depreciation, depletion and amortization	(1,073,664)	(1,147,688)	(1,229,264)
Net capitalized costs	$ 599,237	$ 629,188	$ 794,256

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

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

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

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, 2009, 2010 and 2011 include capitalized general and administrative costs related to acquisition, exploration and development of natural gas and oil properties of $25.1 million, $22.7 million and $27.0 million, respectively. Costs incurred also include asset retirement costs of $6.6 million, $(5.0) million and $(7.8) million during the years ended December 31, 2009, 2010 and 2011, respectively.

	Years Ended December 31,		
	2009	2010	2011
	(in thousands)		
Property acquisition and leasehold costs:			
Unevaluated property	$ 8,972	$ 22,673	$ 17,772
Proved property	22,784	1,048	1,636
Exploration costs	61,547	88,966	131,394
Development costs	97,782	102,283	96,176
Total costs incurred	$191,085	$214,970	$246,978

Estimated Net Quantities of Natural Gas and Oil Reserves

In January 2010, the FASB issued an ASU to amend existing oil and gas reserve accounting and disclosure guidance to align its requirements with the SEC's revised rules regarding oil and gas reserve reporting requirements. The significant revisions involve revised definitions of oil and gas producing activities, changing the pricing used to estimate reserves at period end to a twelve month arithmetic average of the first day of the month prices and additional disclosure requirements. In contrast to the SEC rule, the FASB does not permit the disclosure of probable and possible reserves in the supplemental oil and gas information in the notes to the financial statements. The amendments are effective for annual reporting periods ending on or after December 31, 2009. Application of the revised rules is prospective and companies were not required to change prior period presentation to conform to the amendments. Application of the amended guidance has only resulted in changes to the prices used to determine proved reserves at December 31, 2009 compared to prior periods, which did not result in a significant change to the Company's proved oil and natural gas reserves.

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

The following table sets forth the Company's net proved reserves, including changes, proved developed reserves and proved undeveloped reserves (all within the United States) at the end of each of the three years in the periods ended December 31, 2009, 2010 and 2011.

	Crude Oil, Liquids and Condensate (MBbls)			Natural Gas (MMcf)		
	2009(1)	2010(2)	2011(3)	2009(1)	2010(2)	2011(3)
Beginning of the year reserves	58,159	51,966	42,571	236,166	278,082	255,163
Revisions of previous estimates	3,723	(1,783)	5,857	7,965	(12,097)	(30,047)
Extensions and discoveries(4)	874	—	1,426	38,532	27,749	89,231
Purchases of reserves in place	—	53	—	20,548	—	400
Production	(3,402)	(2,792)	(2,441)	(24,748)	(23,196)	(23,923)
Sales of reserves in place	(7,388)	(4,873)	—	(381)	(15,375)	—
End of year reserves	51,966	42,571	47,413	278,082	255,163	290,824
Proved developed reserves:						
Beginning of year	34,468	29,309	22,270	107,418	126,671	122,928
End of year	29,309	22,270	25,131	126,671	122,928	141,806
Proved undeveloped reserves:						
Beginning of year	23,691	22,657	20,301	128,749	151,411	132,235
End of year	22,657	20,301	22,282	151,411	132,235	149,018

(1) Unescalated twelve month arithmetic average of the first day of the month posted prices of $61.04 per Bbl for oil and natural gas liquids and $3.87 per MMBtu for natural gas were adjusted as described in note (1) above to arrive at prices of $51.15 per Bbl for oil, $37.98 per Bbl for natural gas liquids and $3.80 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2009.

(2) Unescalated twelve month arithmetic average of the first day of the month posted prices of $79.43 per Bbl for oil and natural gas liquids and $4.38 per MMBtu for natural gas were adjusted in note (1) above to arrive at prices of $69.18 per Bbl for oil, $59.85 per Bbl for natural gas liquids and $4.37 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2010.

(3) Unescalated twelve month arithmetic average of the first day of the month posted prices of $96.19 per Bbl for oil and natural gas liquids and $4.12 per MMBtu for natural gas were adjusted in note (1) above to arrive at prices of $99.62 per Bbl for oil, $68.40 per Bbl for natural gas liquids and $4.05 per MMBtu for natural gas, which were used in the determination of proved reserves at December 31, 2011.

(4) Extensions for the years ended December 31, 2009, 2010 and 2011 include 32,001 MMcf, 27,749 MMcf and 89,031 MMcf, respectively, resulting from the Company's infill program in the Sacramento Basin.

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

The following summarizes the policies used in the preparation of the accompanying oil and natural gas reserve disclosures, standardized measures of discounted future net cash flows from proved oil and natural gas reserves and the reconciliations of standardized measures from year to year. The information disclosed, as prescribed by the Oil and Gas Reserve Estimation and Disclosure guidance issued by the FASB, is an attempt to present the information in a manner comparable with industry peers.

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

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

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

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

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

(2) The estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of crude oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves for reserves as of December 31, 2009, 2010 and 2011.

(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,		
	2009	2010	2011
		(in thousands)	
Future cash inflows	$ 3,682,214	$ 4,037,386	$ 5,810,038
Future production costs	(1,490,694)	(1,348,007)	(1,673,857)
Future development and abandonment costs	(676,801)	(620,073)	(672,072)
Future income taxes	(229,549)	(462,093)	(946,166)
Future net cash flows	1,285,170	1,607,213	2,517,943
10% annual discount for estimated timing of cash flows	(592,365)	(704,312)	(1,153,797)
Standardized measure of discounted future net cash flows	$ 692,805	$ 902,901	$ 1,364,146

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

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

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

	Years Ended December 31, (in thousands)		
	2009	2010	2011
Beginning of the year	$ 610,096	$ 692,805	$ 902,901
Changes in prices and production costs	214,179	465,538	473,194
Revisions of previous quantity estimates	59,878	(65,495)	19,096
Changes in future development costs	(11,270)	11,724	84,061
Development costs incurred during the period	49,194	50,740	28,771
Extensions, discoveries and improved recovery, net of related costs	47,177	55,269	258,317
Sales of oil and natural gas, net of production costs	(158,659)	(190,550)	(213,599)
Accretion of discount	61,011	84,065	112,718
Net change in income taxes	(101,663)	(117,547)	(216,559)
Sale of reserves in place	(55,600)	(71,765)	—
Purchases of reserves in place	15,737	1,144	378
Production timing and other	(37,275)	(13,027)	(85,132)
End of year	$ 692,805	$ 902,901	$1,364,146

15. GUARANTOR FINANCIAL INFORMATION

All subsidiaries of the Company other than Ellwood Pipeline Inc. ("Guarantors") have fully and unconditionally guaranteed, on a joint and several basis, the Company's obligations under its 11.50% and 8.875% senior notes. Ellwood Pipeline, Inc. is not a Guarantor (the "Non-Guarantor Subsidiary"). The condensed consolidating financial information for prior periods has been revised to reflect the guarantor and non-guarantor status of the Company's subsidiaries as of December 31, 2011. All Guarantors are 100% owned by the Company. Presented below are the Company's condensed consolidating balance sheets, statements of operations and statements of cash flows as required by Rule 3-10 of Regulation S-X of the Securities Exchange Act of 1934.

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15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2010
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 5,024	$ —	$ —	$ —	$ 5,024
Accounts receivable	29,082	121	399	—	29,602
Inventories	6,229	—	—	—	6,229
Other current assets	4,585	—	—	—	4,585
Income taxes receivable	931	—	—	—	931
Commodity derivatives	26,407	—	—	—	26,407
TOTAL CURRENT ASSETS	72,258	121	399	—	72,778
PROPERTY, PLANT & EQUIPMENT, NET	825,844	(183,940)	6,140	—	648,044
COMMODITY DERIVATIVES	21,462	—	—	—	21,462
INVESTMENTS IN AFFILIATES	520,958	—	—	(520,958)	—
OTHER	8,578	61	—	—	8,639
TOTAL ASSETS	$1,449,100	$(183,758)	$ 6,539	$(520,958)	$ 750,923
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 45,346	$ 50	$ —	$ —	$ 45,396
Interest payable	5,538	—	—	—	5,538
Commodity and interest derivatives	33,483	—	—	—	33,483
TOTAL CURRENT LIABILITIES:	84,367	50	—	—	84,417
LONG-TERM DEBT	633,592	—	—	—	633,592
COMMODITY AND INTEREST DERIVATIVES	23,430	—	—	—	23,430
ASSET RETIREMENT OBLIGATIONS	91,127	1,604	990	—	93,721
INTERCOMPANY PAYABLES (RECEIVABLES)	700,821	(650,346)	(50,475)	—	—
TOTAL LIABILITIES	1,533,337	(648,692)	(49,485)	—	835,160
TOTAL STOCKHOLDERS' EQUITY	(84,237)	464,934	56,024	(520,958)	(84,237)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,449,100	$(183,758)	$ 6,539	$(520,958)	$ 750,923

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING BALANCE SHEETS
AT DECEMBER 31, 2011
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ 8,165	$ —	$ —	$ —	$ 8,165
Accounts receivable	29,492	137	388	—	30,017
Inventories	7,411	—	—	—	7,411
Other current assets	4,296	—	—	—	4,296
Commodity derivatives	47,768	—	—	—	47,768
TOTAL CURRENT ASSETS	97,132	137	388	—	97,657
PROPERTY, PLANT & EQUIPMENT, NET	980,041	(184,110)	14,534	—	810,465
COMMODITY DERIVATIVES	3,242	—	—	—	3,242
INVESTMENTS IN AFFILIATES	529,494	—	—	(529,494)	—
OTHER	18,320	60	—	—	18,380
TOTAL ASSETS	$1,628,229	$(183,913)	$ 14,922	$(529,494)	$ 929,744
LIABILITIES AND STOCKHOLDERS' EQUITY					
CURRENT LIABILITIES:					
Accounts payable and accrued liabilities	$ 53,098	$ —	$ —	$ —	$ 53,098
Interest payable	21,854	—	—	—	21,854
Commodity and interest derivatives	2,490	—	—	—	2,490
TOTAL CURRENT LIABILITIES:	77,442	—	—	—	77,442
LONG-TERM DEBT	686,958	—	—	—	686,958
COMMODITY AND INTEREST DERIVATIVES	308	—	—	—	308
ASSET RETIREMENT OBLIGATIONS	89,604	1,733	671	—	92,008
INTERCOMPANY PAYABLES (RECEIVABLES)	700,889	(652,294)	(48,595)	—	—
TOTAL LIABILITIES	1,555,201	(650,561)	(47,924)	—	856,716
TOTAL STOCKHOLDERS' EQUITY	73,028	466,648	62,846	(529,494)	73,028
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,628,229	$(183,913)	$ 14,922	$(529,494)	$ 929,744

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2009
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 235,702	$ 31,461	$ —	$ —	$ 267,163
Other	2,810	114	5,667	(5,260)	3,331
Total revenues	238,512	31,575	5,667	(5,260)	270,494
EXPENSES:					
Lease operating expense	81,284	11,935	1,994	—	95,213
Production and property taxes	9,494	537	97	—	10,128
Transportation expense	8,025	77	—	(4,939)	3,163
Depletion, depreciation and amortization	78,544	7,527	155	—	86,226
Accretion of asset retirement obligations	5,256	456	53	—	5,765
General and administrative, net of amounts capitalized	34,058	2,881	321	(321)	36,939
Total expenses	216,661	23,413	2,620	(5,260)	237,434
Income from operations	21,851	8,162	3,047	—	33,060
FINANCING COSTS AND OTHER:					
Interest expense, net	44,669	(6)	(3,679)	—	40,984
Amortization of deferred loan costs	2,862	—	—	—	2,862
Interest rate derivative losses, net	16,676	—	—	—	16,676
Loss on extinguishment of debt	8,493	—	—	—	8,493
Commodity derivative losses (gains), net	25,743	—	—	—	25,743
Total financing costs and other	98,443	(6)	(3,679)	—	94,758
Equity in subsidiary income	9,234	—	—	(9,234)	—
Income (loss) before income taxes	(67,358)	8,168	6,726	(9,234)	(61,698)
Income tax provision (benefit)	(20,060)	3,104	2,556	—	(14,400)
Net income (loss)	$ (47,298)	$ 5,064	$ 4,170	$ (9,234)	$ (47,298)

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

**CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2010
(in thousands)**

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 280,028	$ 10,580	$ —	$ —	$ 290,608
Other	4,273	82	4,986	(4,657)	4,684
Total revenues	284,301	10,662	4,986	(4,657)	295,292
EXPENSES:					
Lease operating expenses	79,624	2,724	1,907	—	84,255
Production and property taxes	6,153	405	143	—	6,701
Transportation expense	13,401	13	—	(4,312)	9,102
Depletion, depreciation and amortization	76,105	1,856	543	—	78,504
Accretion of asset retirement obligations	5,914	259	68	—	6,241
General and administrative, net of amounts capitalized	35,220	2,235	444	(345)	37,554
Total expenses	216,417	7,492	3,105	(4,657)	222,357
Income from operations	67,884	3,170	1,881	—	72,935
FINANCING COSTS AND OTHER:					
Interest expense, net	44,418	(1)	(3,833)	—	40,584
Amortization of deferred loan costs	2,362	—	—	—	2,362
Interest rate derivative losses, net	31,818	—	—	—	31,818
Commodity derivative losses (gains), net	(68,049)	—	—	—	(68,049)
Total financing costs and other	10,549	(1)	(3,833)	—	6,715
Equity in subsidiary income	5,509	—	—	(5,509)	—
Income (loss) before income taxes	62,844	3,171	5,714	(5,509)	66,220
Income tax provision (benefit)	(4,676)	1,205	2,171	—	(1,300)
Net income (loss)	$ 67,520	$ 1,966	$ 3,543	$ (5,509)	$ 67,520

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15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
YEAR ENDED DECEMBER 31, 2011
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
REVENUES:					
Oil and natural gas sales	$ 321,813	$ 1,610	$ —	$ —	$ 323,423
Other	4,963	56	4,560	(4,224)	5,355
Total revenues	326,776	1,666	4,560	(4,224)	328,778
EXPENSES:					
Lease operating expense	92,402	54	1,644	—	94,100
Production and property taxes	6,581	(336)	131	—	6,376
Transportation expense	13,220	—	—	(3,872)	9,348
Depletion, depreciation and amortization	86,069	104	(356)	—	85,817
Accretion of asset retirement obligations	6,231	129	63	—	6,423
General and administrative, net of amounts capitalized	39,069	1	468	(352)	39,186
Total expenses	243,572	(48)	1,950	(4,224)	241,250
Income from operations	83,204	1,714	2,610	—	87,528
FINANCING COSTS AND OTHER:					
Interest expense, net	65,324	—	(4,211)	—	61,113
Amortization of deferred loan costs	2,310	—	—	—	2,310
Interest rate derivative losses, net	1,083	—	—	—	1,083
Loss on extinguishment of debt	1,357	—	—	—	1,357
Commodity derivative losses (gains), net	(40,649)	—	—	—	(40,649)
Total financing costs and other	29,425	—	(4,211)	—	25,214
Equity in subsidiary income	5,292	—	—	(5,292)	—
Income (loss) before income taxes	59,071	1,714	6,821	(5,292)	62,314
Income tax provision (benefit)	(3,243)	651	2,592	—	—
Net income (loss)	$ 62,314	$ 1,063	$ 4,229	$ (5,292)	$ 62,314

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2009
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 88,414	$ 23,804	$ 6,473	$ —	$ 118,691
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(160,069)	(12,699)	(2,056)	—	(174,824)
Acquisitions of oil and natural gas properties	(22,794)	—	—	—	(22,794)
Expenditures for property and equipment and other	(1,802)	(186)	—	—	(1,988)
Proceeds from sale of oil and natural gas properties	—	197,653	—	—	197,653
Net cash provided by (used in) investing activities	(184,665)	184,768	(2,056)	—	(1,953)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	212,989	(208,572)	(4,417)	—	—
Proceeds from long-term debt	276,562	—	—	—	276,562
Principal payments on long-term debt	(388,907)	—	—	—	(388,907)
Payments for deferred loan costs	(5,221)	—	—	—	(5,221)
Proceeds from stock incentive plans and other	1,056	—	—	—	1,056
Net cash provided by (used in) financing activities	96,479	(208,572)	(4,417)	—	(116,510)
Net increase (decrease) in cash and cash equivalents	228	—	—	—	228
Cash and cash equivalents, beginning of period	190	1	—	—	191
Cash and cash equivalents, end of period	$ 418	$ 1	$ —	$ —	$ 419

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2010
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 149,248	$ 5,037	$ 6,388	$ —	$ 160,673
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(203,814)	(1,001)	(3,568)	—	(208,383)
Acquisitions of oil and natural gas properties	(4,112)	—	—	—	(4,112)
Expenditures for property and equipment and other	(3,238)	—	—	—	(3,238)
Proceeds from sale of oil and natural gas properties	8,476	98,961	—	—	107,437
Net cash provided by (used in) investing activities	(202,688)	97,960	(3,568)	—	(108,296)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	105,818	(102,998)	(2,820)	—	—
Proceeds from long-term debt	135,000	—	—	—	135,000
Principal payments on long-term debt	(197,035)	—	—	—	(197,035)
Payments for deferred loan costs	(396)	—	—	—	(396)
Proceeds from stock incentive plans and other	14,659	—	—	—	14,659
Net cash provided by (used in) financing activities	58,046	(102,998)	(2,820)	—	(47,772)
Net increase (decrease) in cash and cash equivalents	4,606	(1)	—	—	4,605
Cash and cash equivalents, beginning of period	418	1	—	—	419
Cash and cash equivalents, end of period	$ 5,024	$ —	$ —	$ —	$ 5,024

VENOCO, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

YEARS ENDED DECEMBER 31, 2009, 2010 AND 2011

15. GUARANTOR FINANCIAL INFORMATION (Continued)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED DECEMBER 31, 2011
(in thousands)

	Venoco, Inc.	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ 117,075	$ 1,882	$ 6,539	$ —	$ 125,496
CASH FLOWS FROM INVESTING ACTIVITIES:					
Expenditures for oil and natural gas properties	(236,022)	66	(8,601)	—	(244,557)
Acquisitions of oil and natural gas properties	(253)	—	—	—	(253)
Expenditures for property and equipment and other	(1,671)	—	—	—	(1,671)
Net cash provided by (used in) investing activities	(237,946)	66	(8,601)	—	(246,481)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Net proceeds from (repayments of) intercompany borrowings	(114)	(1,948)	2,062	—	—
Proceeds from long-term debt	588,000	—	—	—	588,000
Principal payments on long-term debt	(535,311)	—	—	—	(535,311)
Payments for deferred loan costs	(12,669)	—	—	—	(12,669)
Proceeds from issuance of common stock	82,800	—	—	—	82,800
Stock issuance costs	(629)	—	—	—	(629)
Proceeds from stock incentive plans and other	1,935	—	—	—	1,935
Net cash provided by (used in) financing activities	124,012	(1,948)	2,062	—	124,126
Net increase (decrease) in cash and cash equivalents	3,141	—	—	—	3,141
Cash and cash equivalents, beginning of period	5,024	—	—	—	5,024
Cash and cash equivalents, end of period	$ 8,165	$ —	$ —	$ —	$ 8,165

Exhibit 10.12

EMPLOYMENT AGREEMENT

This Employment Agreement ("Agreement") is entered into effective as of the 15th day of December 2011 by and between Venoco, Inc., a Delaware corporation ("Company"), and Mark DePuy ("Employee").

WHEREAS, the Company desires to employ Employee as the Senior Vice President, Business Development & Acquisitions, and Employee desires to accept such employment;

NOW, THEREFORE, in consideration of the mutual covenants, representations, warranties and agreements contained herein, and for other valuable consideration, the receipt and adequacy of which are hereby acknowledged, the parties agree as follows:

1. Employment. The Company hereby employs Employee, and Employee hereby accepts employment by the Company, as Senior Vice President Business Development & Acquisitions on the terms and conditions set forth in this Agreement.

2. Term of Employment. Subject to the provisions for earlier termination provided in the Agreement, the term of this Agreement (the "Term") shall commence on the effective date of this Agreement as stated above and shall terminate on December 31, 2013; *provided, however,* commencing on January 1, 2013 and on each January 1 thereafter, the term of this Agreement shall automatically be extended one additional year unless, not later than September 30 of the preceding year, the Board of Directors of the Company (the "Board") shall give written notice to Employee that the Term of the Agreement shall cease to be so extended; *provided, further,* that if a Change in Control, as defined in Section 8, shall have occurred during the original or extended Term of this Agreement, the Term shall continue in effect for a period of not less than 36 months beyond the date of such Change in Control. In no event, however, shall the Term of this Agreement extend beyond the end of the calendar month in which Employee's 65th birthday occurs. Notwithstanding any provision of this Agreement to the contrary, termination of this Agreement shall not alter or impair any rights or benefits of Employee (or Employee's estate or beneficiaries) that have arisen under this Agreement on or prior to such termination, including, without limitation, the provisions of Sections 9(c), 15 and 18.

3. Employee's Duties. During the Term of this Agreement Employee shall serve as the Senior Vice President, Business Development & Acquisitions of the Company, based in Denver, Colorado and with such customary duties and responsibilities as may from time to time be assigned to him by the Chief Executive Officer and the Board, provided that such duties are at all times consistent with the duties of such position. Employee agrees to devote reasonable attention and time during normal business hours to the business and affairs of the Company and, to the extent necessary to discharge the duties

and responsibilities assigned to Employee hereunder, to use reasonable best efforts to perform faithfully and efficiently such duties and responsibilities.

4. Base Compensation. For services rendered by Employee under this Agreement, the Company shall pay to Employee a base salary ("Base Compensation") of $325,000.00 per annum, payable in accordance with the Company's customary payroll practice for its executive officers. The amount of Base Compensation shall be reviewed periodically and may be increased to reflect inflation or such other adjustments as the Board may deem appropriate but Base Compensation, as increased, may not be decreased thereafter.

5. Signing and Annual Bonuses. Upon Employee's execution of this Agreement, the Company shall pay to Employee a signing bonus of $75,000.00 (which bonus shall be returned to the Company in full if Employee terminates his employment within one year of the execution of this Agreement). Employee shall be eligible to participate in the Company's incentive compensation plan; under which cash bonuses are paid to senior executives based upon the performance of both the Company and the employee. The target annual bonus for the position of Senior Vice President Business Development & Acquisitions shall be 65% of Employees annual Base Compensation. The annual bonus award will be determined by the Compensation Committee each year for performance during the prior year and paid on April 1 of the year in which it is determined. The amount of the bonus shall be based on performance of the Employee and the Company as measured against goals established by the Compensation Committee. The annual cash bonus payable in 2012 for performance in 2011 shall be $25,000.

6. Restricted Share Grant. Employee shall receive an initial grant of 25,000 restricted shares of the Company's stock which shall vest over a period of four years.

7. Additional Benefits. In addition to the other compensation and benefits provided for in this Agreement, Employee shall be entitled to receive all fringe benefits and perquisites offered by the Company to its executive officers. Such benefits shall include, without limitation, 5 weeks paid vacation per year; participation in the Company's 401(k) Plan; participation in other incentive and benefit plans offered generally to key employees; participation in various employee benefit plans or programs provided to the employees of the Company in general, subject to the regular eligibility requirements with respect to each of such benefit plans or programs; and such other benefits or perquisites as may be approved by the Board during the Term of this Agreement. Nothing in this paragraph shall be deemed to prohibit the Company from making any changes in any plans, programs or benefits described in this Section 7, provided the change similarly affects all executives of the Company similarly situated.

8. Change in Control.

For purposes of this Agreement, a "Change in Control" shall mean the occurrence of one of the following events:

(i) Any "person" (as such term is used in Section 13(d) and 14(d) of the Exchange Act) other than Timothy M. Marquez, Bernadette B. Marquez, their respective legal representatives, devisees, donees and heirs and any Trust for the benefit of either or both of Timothy M. Marquez and Bernadette B. Marquez and/or the issue of either of them (the "Marquez Family") becomes a "beneficial owner" (as defined in Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of securities of the Company representing more than 50% of the combined voting power of the Company's then outstanding securities, or the outstanding securities of a successor entity in the event of a business combination between the Company and another entity; provided that for purposes of this paragraph a "person" shall not include the entity with which the Company may consummate a business combination;

(ii) the stockholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets. For purposes of this clause (ii), the term "the sale or disposition by the Company of all or substantially all of the Company's assets" shall mean a sale or other disposition transaction or series of related transactions (other than transactions related to the creation of a master limited partnership or royalty trust in which the Company continues its corporate existence), involving assets of the Company or of any direct or indirect subsidiary of the Company (including the stock of any direct or indirect subsidiary of the Company) in which the value of the assets or stock being sold or otherwise disposed of (as measured by the purchase price being paid therefor or by such other method as the Board determines is appropriate in a case where there is no readily ascertainable purchase price) constitutes more than two-thirds of the "fair market value of the Company" (as hereinafter defined). For purposes of the preceding sentence, the "fair market value of the Company" shall be the aggregate market value of the Company's outstanding common stock (on a fully diluted basis) plus the aggregate market value of the Company's other outstanding equity securities. The aggregate market value of the Company's equity securities shall be determined by multiplying the number of shares of the Company's common stock (on a fully diluted basis) outstanding on the date of the execution and delivery of a definitive agreement with respect to the transaction or series of related transactions (the "Transaction Date") by the average closing price of such security for the ten trading days immediately preceding the Transaction Date, or if not publicly traded, by such other method as the Board shall determine is appropriate; or

(iii) the Marquez Family is no longer the largest beneficial owner of the Company's outstanding voting securities and Timothy Marquez is no longer the CEO or Chairman of the Board.

9. Termination. This Agreement may be terminated prior to the end of its Term as set forth below.

(a) Resignation. Employee may resign, including by reason of retirement, his position at any time. In the event of such resignation, except in the case of resignation on or following a Change in Control for Good Reason (as defined below), Employee shall not be entitled to further compensation pursuant to this Agreement.

(b) Death. If Employee's employment is terminated due to his death, the Company shall pay Employee's beneficiaries or legal representatives (i) within 15 days, any Base Compensation and vacation pay which had accrued hereunder at the date of Employee's death; and (ii) the same benefits that Employee would receive in the event of Discharge following a Change in Control as described in Section 9(c)(i), below, as though Employee has been terminated following a Change in Control.

(c) Discharge.

(i) The Company may terminate this Agreement and Employee's employment for any reason deemed sufficient by the Company upon notice as provided in Section 12. However, in the event that Employee's employment is terminated during the Term by the Company on or following a Change in Control and for any reason other than his Misconduct (as defined in Section 9(c)(ii) below) then: (A) the Company shall pay in a lump sum, in cash, to Employee, within 15 days of the Date of Termination, an amount equal to three times the sum of (1) Employee's Base Compensation, (2) an amount equal to the highest incentive award paid or payable, as the case may be, to Employee under the Company's Incentive Compensation Plan during the current year and the three years prior to termination, (3) an amount equal to the amount of contributions that the Company would have made on behalf of Employee under the Company's 401(k) Plan during the prior year disregarding any limitations on benefits or covered compensation imposed by I.R.C. Sections 401(a)(17), 401(k), 401(m) or 415; (B) for the 36-month period after such Date of Termination, the Company shall provide or arrange to provide Employee (and Employee's dependents) with group health insurance benefits substantially similar to those which Employee (and Employee's dependents) were receiving immediately prior to the Notice of Termination, with the Employee charged a monthly premium(s) for such coverage(s) that does not exceed the premium(s) charged to an active employee for comparable coverage(s); benefits otherwise receivable by Employee pursuant to this clause (B) shall be reduced to the extent comparable benefits are actually received by Employee (and Employee's dependents) during the 36-month period following Employee's termination, and any such benefits actually received by Employee shall be reported to the Company (to the extent coverage and/or benefits received under a self-insured health plan of the Company (any successor or affiliate) are taxable to Employee, the Company shall make Employee "whole" on a net after tax basis, with such make whole payments to be made during the month of the related health care coverage); (C) within 30 days of the Date of Termination or, if later, the first date on which such payment would not subject Employee to suit under Section 16(b) of the Securities Exchange Act of 1934, if applicable, the Company shall offer to pay to Employee for cancellation of all outstanding stock-based awards then held by Employee on the Date of Termination (collectively, "Awards"), a lump sum amount in cash equal to the sum of the value (with respect to an option or stock appreciation right, the "spread" and with respect to restricted stock or phantom stock, the value of an unrestricted share) of all such Awards, calculated, where applicable, as if all corporate performance goals had been achieved (thus warranting full value of the Award) and in the case where the Company's stock is not publicly traded, using a fair market value on the Date of Termination as determined by an independent third party agreeable to the Company and Employee; and (D) within 30 days after the Date of Termination, the Company shall pay to Employee an amount equal to 36 times the excess of (i) the monthly premium payable immediately prior to the Notice of Termination for life, disability and accident benefits substantially similar to those which employee (and Employee's dependents) were receiving at such time, over (ii) the aggregate monthly premiums(s) charged to the Executive for such coverage at such time. Each of the payments described in Section (A) — (D) of this Section shall be deemed to be separate payments for purposes of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code").

(ii) Notwithstanding the foregoing provisions of this Section 9, in the event Employee is terminated because of Misconduct, the Company shall have no compensation obligations pursuant to this Agreement after the Date of Termination. As used herein, "Misconduct" means (a) the willful and continued failure by Employee to substantially perform his duties with the Company (other than any such failure resulting from Employee's incapacity due to physical or mental illness or any such actual or anticipated failure after the issuance of a Notice of Termination by Employee for Good Reason), after a written demand for substantial performance is delivered to Employee by the Board, which demand specifically identifies the manner in which the Board believes that Employee has not substantially performed his duties, or (b) the willful engaging by Employee in conduct which is demonstrably and materially injurious to the Company, monetarily or otherwise. For purposes hereof, no act, or failure to act, on Employee's part shall be deemed "willful" unless done, or omitted to be done, by Employee not in good faith and without reasonable belief that Employee's action or omission was in the best interest of the Company. Notwithstanding the foregoing, Employee shall not be deemed to have been terminated for Misconduct unless and until there shall have been delivered to Employee a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board at a meeting of the Board called and held for such purpose (after reasonable notice to Employee and an opportunity for Employee, together with Employee's counsel, to be heard before the Board), finding that in the good faith opinion of the Board Employee was guilty of conduct set forth above and specifying the particulars thereof in detail.

(iii) If the Company terminates this Agreement and Employee's employment before the expiration of the Term, other than following a Change in Control and other than for Misconduct, then, instead of the severance amount described in Section 9(c)(1)(A), the severance amount shall be equal to two times the sum of (1) Employee's Base Compensation and (2) an amount equal the greater of $50,000 or the highest cash incentive award paid or payable, as the case may be, during the three years prior to termination, payable at the same time and in the same form as the severance amount set forth in Section 9(c)(1)(A) (cash lump sum within 15 days of the Date of Termination). The Employee shall not be entitled to any of the other payments or benefits described in Sections 9(c)(1)(B) — (D) above.

(d) Disability.

(i) If Employee shall have been absent from the full-time performance of Employee's duties with the Company for six consecutive months as a result of Employee's incapacity due to physical or mental illness, as determined by Employee's physician, and within 30 days after written Notice of Termination is given by the Company Employee shall not have returned to the full-time performance of Employee's duties, Employee's employment may be terminated by the Company for "Disability" and Employee shall upon such termination be entitled to receive the payments described in Section 9(c)(i) as though Employee has been terminated following a Change in Control.

(ii) If Employee fails during any period during the Term to perform Employee's full-time duties with the Company as a result of incapacity due to physical or mental illness, as determined by Employee's physician, Employee shall continue to receive his Base Compensation, together with all compensation payable to Employee under the Company's Long Term Disability Plan or other similar plan during such period until this Agreement is terminated.

(e) Resignation for Good Reason. In the event of a Change in Control, Employee shall be entitled to terminate his employment for Good Reason as defined herein. If Employee terminates his employment for Good Reason, Employee shall be entitled to the compensation and benefits provided in Paragraph 9(c)(i) hereof. "Good Reason" shall mean (1) the breach of any of the Company's obligations under this Agreement without Employee's express written consent or (2) the occurrence of any of the following circumstances without Employee's express written consent unless such breach or circumstances are fully corrected prior to the Date of Termination specified in the Notice of Termination pursuant to Subsection 9(f) given in respect thereof:

(i) the assignment to Employee of any duties that, in the good faith opinion of Employee, are inconsistent with the position in the Company that Employee held immediately prior thereto, or an adverse alteration (as determined in good faith by Employee) in the nature or status of Employee's office, title, responsibilities, including reporting responsibilities, or the conditions of Employee's employment from those in effect immediately prior thereto or a failure to maintain Employee as Senior Vice President, Business Development & Acquisitions;

(ii) a reduction in Employee's Base Compensation;

(iii) the failure by the Company to pay to Employee any portion of Employee's current compensation or to pay to Employee any portion of an installment of deferred compensation under any deferred compensation program of the Company within seven days of the date such compensation is due;

(iv) the failure by the Company to continue in effect any compensation plan in which Employee participates that is material to Employee's total compensation unless an equitable arrangement (embodied in an ongoing substitute or alternative plan) has been made with respect to such plan, or the failure by the Company to continue Employee's participation therein (or in such substitute or alternative plan) on a basis not materially less favorable, both in terms of the amount of benefits provided and the level of Employee's participation relative to other participants, as existed at the time of the Change in Control;

(v) the failure by the Company to continue to provide Employee with benefits substantially similar to those enjoyed by Employee under any of the Company's life insurance, medical, health and accident, or disability plans in which Employee was participating at the time of this Agreement; the taking of any action by the Company which would directly or indirectly materially reduce any of such benefits or deprive Employee of any material fringe benefit enjoyed by Employee at the time of this Agreement, or the failure by the Company to provide Employee with the number of paid vacation days to which Employee is entitled on the basis of years of service with the Company (and its predecessors) in accordance with the Company's normal vacation policy in effect at the time of the Change in Control;

(vi) the failure of the Company to obtain a satisfactory agreement from any successor to assume and agree to perform this Agreement, as contemplated in Section 14 hereof;

(vii) the amendment, modification or repeal of any provision of the Certificate of Incorporation, or the Bylaws of the Company which was in effect immediately prior to time of this Agreement, if such amendment, modification or repeal would materially adversely effect Employee's right to indemnification by the Company; or

(viii) any purported termination of Employee's employment that is not effected pursuant to a Notice of Termination satisfying the requirements of Subsection (f) hereof, which purported termination shall not be effective for purposes of this Agreement.

Notwithstanding anything in this Agreement to the contrary, if Employee's employment with the Company terminates prior to, but within six months of, the date on which a Change in Control occurs and it is reasonably demonstrated by Employee that such termination of employment was (i) by the Company in connection with or anticipation of the Change in Control or (ii) by Employee under circumstances which would have constituted Good Reason if the circumstances arose on or after the Change in Control, then, for purposes of this Agreement, Employee shall be deemed to have continued employment with the Company until the date of the Change in Control and then terminated his employment on such date for Good Reason.

Employee's right to terminate employment pursuant to this subsection shall not be affected by Employee's incapacity due to physical or mental illness. In addition, Employee's continued employment following any event, act or omission, regardless of the length of such continued employment, shall not constitute Employee's consent to, or a waiver of Employee's rights with respect to, such event, act or omission constituting a Good Reason circumstance hereunder.

(f) Notice of Termination. On and after a Change in Control, any purported termination of Employee's employment by the Company or by Employee shall be communicated by written Notice of Termination to the other party hereto in accordance with Section 12 hereof. For purposes of this Agreement, a "Notice of Termination" shall mean a notice which shall set forth in reasonable detail the reason for termination of Employee's employment, or in the case of resignation for Good Reason, said notice must specify in reasonable detail the basis for such resignation. No purported termination which is not effected pursuant to this Section 9(f) shall be effective.

(g) Date of Termination. "Date of Termination" shall mean the date the employee incurs a "separation from service" within the meaning of Code Section 409A. Either party may, within 15 days after any Notice of Termination is given, provide notice to the other party pursuant to Section 12 hereof that a dispute exists concerning the termination. Notwithstanding the pendency of any such dispute, the Company will continue to pay Employee his full compensation in effect when the notice giving rise to the dispute was given (including, but not limited to, Base Compensation) and continue Employee as a participant in all compensation, benefit and insurance plans in which Employee was participating when the notice giving rise to the dispute was given, until the dispute is finally resolved in accordance with Section 18 hereof, but in no event past the expiration date of this Agreement. All payments pursuant to this Section shall be made at the same time or times as otherwise specified in this Agreement or pursuant to the terms of such plan or plans. Any payments and benefits provided during such period of dispute shall not reduce any other payments or benefits due Employee under this Agreement nor shall Employee be liable to repay the Company for such payments and benefits if it is finally determined the Employee is not entitled to payments under the other provisions of this Agreement following Employee's termination of employment.

(h) Mitigation. Except as otherwise provided in Section 9(c)(i) with regard to group health benefits, Employee shall not be required to mitigate the amount of any payment provided for in this Section 9 by seeking other employment or otherwise, nor shall the amount of any payment or benefit provided for in this Agreement be reduced by any compensation earned by Employee as a result of employment by another employer, self-employment earnings, by retirement benefits, by offset against any amount claimed to be owing by Employee to the Company, or otherwise. No amounts payable to Employee under any plan or program of the Company shall reduce or offset any amounts payable to Employee under this Agreement.

(i) Section 280G.

(1) To provide Employee with adequate protection in connection

with his ongoing employment with the Company, this Agreement provides Employee with various benefits in the event of termination of Employee's employment with the Company. If Employee's employment is terminated following a "change in control" of the Company, within the meaning of Section 280G of the Code, a portion of those benefits could be characterized as "excess parachute payments" within the meaning of Section 280G of the Code. With respect to issues related to excess parachute payments, the parties have agreed as set forth herein.

(2) Anything in this Agreement to the contrary notwithstanding, the payments and distributions by the Company or any other person to or for the benefit of Employee (whether paid or payable or distributed or distributable pursuant to the terms of this Agreement or otherwise (a "Payment")) shall be reduced so that no such Payment shall be subject to the excise tax imposed by Section 4999 of the Code or any interest or penalties would be incurred by Employee with respect to such excise tax (such excise tax, together with any such interest and penalties, are hereinafter collectively referred to as the "Excise Tax"), if the Company shall determine that the amount of the Payments that Employee would retain on any after-tax, present value basis would be increased as a result of such reduction by $5,000 or more.

(3) In the event that a reduction in Payments is required pursuant to the immediately preceding paragraph, then, except as provided below with respect to Payments that consist of health and welfare benefits, the reduction in Payments shall be implemented by determining the "Parachute Payment Ratio" (as defined below) for each Payment and then reducing the Payments in order beginning with the Payment with the highest Parachute Payment Ratio. For Payments with the same Parachute Payment Ratio, such Payments shall be reduced based on the time of payment of such Payments, with amounts being paid furthest in the future being reduced first. For Payments with the same Parachute Payment Ratio and the same time of payment, such Payments shall be reduced on a pro-rata basis (but not below zero) prior to reducing Payments next in order for reduction. For purposes of this Section, "Parachute Payment Ratio" shall mean a fraction, the numerator of which is the value of the applicable Payment as determined for purposes of Code Section 280G, and the denominator of which is the financial present value of such Parachute Payment, determined at the date such payment is treated as made for purposes of Code Section 280G (the "Valuation Date"). In determining the denominator for purposes of the preceding sentence (1) present values shall be determined using the same discount rate that applies for purposes of discounting payments under Code Section 280G; (2) the financial value of payments shall be determined

generally under Q&A 12, 13 and 14 of Treasury Regulation 1.280G-1; and (3) other reasonable valuation assumptions as determined by the Company shall be used. Notwithstanding the foregoing, Payments that consist of health and welfare benefits shall be reduced after all other Payments, with health and welfare Payments being made furthest in the future being reduced first.

(j) Section 409A.

(1) Anything in this Agreement to the contrary notwithstanding, if (1) on the date of termination of Employee's employment with the Company, any of the Company's stock is publicly traded on an established securities market or otherwise (within the meaning of Section 409A(a)(2)(B)(i) of the Code) and (2) as a result of such termination, the Employee would receive any payment that, absent the application of this paragraph 9(j), would be subject to interest and additional tax imposed pursuant to Section 409A(a) of the Code as a result of the application of Section 409A(2)(B)(i) of the Code, then no such payment shall be payable prior to the date that is the earliest of (i) 6 months after the Employee's termination date, (ii) the Employee's death or (iii) such other date as will cause such payment not to be subject to such interest and additional tax.

(2) It is the intention of the parties that payments or benefits payable under this Agreement not be subject to the additional tax imposed pursuant to Section 409A of the Code and this Agreement shall be interpreted accordingly. To the extent such potential payments or benefits could become subject to such Section, the parties shall cooperate to amend this Agreement with the goal of giving Employee the economic benefits described herein in a manner that does not result in such tax being imposed.

(3) All taxable expenses or other reimbursements or in-kind benefits under this Agreement shall be made on or prior to the last day of the taxable year following the taxable year in which such expenses were incurred by Employee, (ii) any right to reimbursement or in kind benefits is not subject to liquidation or exchange for another benefit, and (iii) no such reimbursement, expenses eligible for reimbursement, or in-kind benefits provided in any taxable year shall in any way affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other taxable year.

(4) The Employee shall have no right to designate the date of any payment hereunder.

(5) Each payment provided for in this Agreement shall, to the extent permissible under Code Section 409A, be deemed a separate payment for purposes of Code Section 409A.

10. Non-exclusivity of Rights. Nothing in this Agreement shall prevent or limit Employee's continuing or future participation in any benefit, bonus, incentive or other plan or program provided by the Company or any of its affiliated companies and for which Employee may qualify, nor shall anything herein limit or otherwise adversely affect such rights as Employee may have under any stock option or other agreements with the Company or any of its affiliated companies.

11. Assignability. The obligations of Employee hereunder are personal and may not be assigned or delegated by him or transferred in any manner whatsoever, nor are such obligations subject to involuntary alienation, assignment or transfer. The Company shall have the right to assign this Agreement and to delegate all rights, duties and obligations hereunder, either in whole or in part, to any parent, affiliate, successor or subsidiary organization or company of the Company, so long as the obligations of the Company under this Agreement remain the obligations of the Company.

12. Notice. For the purpose of this Agreement, notices and all other communications provided for in the Agreement shall be in writing and shall be deemed to have been duly given when delivered or mailed by United States registered mail, return receipt requested, postage prepaid, addressed to the Company at its principal office address, directed to the attention of the Board with a copy to the Secretary of the Company, and to Employee at Employee's residence address on the records of the Company or to such other address as either party may have furnished to the other in writing in accordance herewith except that notice of change of address shall be effective only upon receipt.

13. Validity. The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement, which shall remain in full force and effect.

14. Successors; Binding Agreement.

(a) The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to expressly assume and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place. As used herein, the term "Company" shall include any successor to its business and/or assets as aforesaid which executes and delivers the Agreement provided for in this Section 14 or which otherwise becomes bound by all terms and provisions of this Agreement by operation of law.

(b) This Agreement and all rights of Employee hereunder shall inure to the benefit of and be enforceable by Employee's personal or legal representatives, executors, administrators, successors, heirs, distributees, devisees and legatees. If Employee should die while any amounts would be payable to him hereunder if he had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with the terms of this Agreement to Employee's devisee, legatee, or other designee or, if there be no such designee, to Employee's estate.

15. Indemnification. In consideration of the premises and of the mutual agreements set forth in this Agreement, the parties hereto further agree as follows:

(a) The Company shall pay on behalf of Employee and Employee's executors, administrators or assigns, any amount which Employee is or becomes legally obligated to pay as a result of any claim or claims made against Employee by reason of the fact that Employee served as an employee, director and/or officer of the Company or because of any actual or alleged breach of duty, neglect, error, misstatement, misleading statement, omission or other act done, or suffered or wrongfully attempted by Employee in Employee's capacity as an employee, Director and/or Officer of the Company. The payments that the Company will be obligated to make hereunder shall include (without limitation) damages, judgments, settlements, costs and expenses of investigation, costs and expenses of defense of legal actions, claims and proceedings and appeals therefrom, and costs of attachments and similar bonds; *provided, however*, that the Company shall not be obligated to pay fines or other obligations or fees imposed by law or otherwise that it is prohibited by applicable law from paying as indemnity or for any other reason.

(b) Costs and expenses (including, without limitation, attorneys' fees) incurred by Employee in defending or investigating any action, suit, proceeding or claim shall be paid by the Company in advance of the final disposition of such matter upon receipt of a written undertaking by or on behalf of Employee to repay any such amounts if it is ultimately determined that Employee is not entitled to indemnification under the terms of this Agreement.

(c) If a claim under this Agreement is not paid by or on behalf of the Company within ninety days after a written claim has been received by the Company, Employee may at any time thereafter bring suit against the Company to recover the unpaid amount of the claim and, if successful in whole or in part, Employee shall also be entitled to be paid the expense of prosecuting such claim.(d) In the event of payment under this Agreement, the Company shall be subrogated to the extent of such payment to all of the rights of recovery of Employee, who shall execute all papers required and shall do everything that may be necessary to secure such rights, including the execution of such documents necessary to enable the Company effectively to bring suit to enforce such rights.
(e) The Company shall not be liable under this Agreement to make any payment in connection with any claim made against Employee:(1) for which payment is actually made to Employee under an insurance policy maintained by the Company, except in respect of any excess beyond the amount of payment under such insurance;(2) for which Employee is indemnified by the Company

otherwise than pursuant to this Agreement;(3) based upon or attributable to Employee gaining in fact any personal profit or advantage to which Employee was not legally entitled;(4) for an accounting of profits made from the purchase or sale by Employee of securities of the Company within the meaning of Section 16(b) of the Securities Exchange Act of 1934 and amendments thereto; or(5) brought about or contributed to by the dishonesty of Employee; *provided, however,* that notwithstanding the foregoing, Employee shall be protected under this Agreement as to any claims upon which suit may be brought alleging dishonesty on the part of Employee, unless a judgment or other final adjudication thereof adverse to Employee shall establish that Employee committed acts of active and deliberate dishonesty with actual dishonest purpose and intent, which acts were material to the cause of action so adjudicated.

(f) Employee, as a condition precedent to his right to be indemnified under this Agreement, shall give to the Company notice in writing as soon as practicable of any claim made against him for which indemnity will or could be sought under this Agreement. Notice to the Company shall be directed to the Company, Attention: Secretary (or such other address as the Company shall designate in writing to Employee). Notice shall be deemed received if sent by prepaid mail properly addressed, the date of such notice being the date postmarked. In addition, Employee shall give the Company such information and cooperation as it may reasonably require and as shall be within Employee's power.

(g) Nothing herein shall be deemed to diminish or otherwise restrict Employee's right to indemnification under any provision of the Certificate of Incorporation or Bylaws of the Company or under Delaware law.

(h) During the Term and for a period of six years thereafter, the Company shall cause Employee to be covered by and named as an insured under a policy or contract of insurance obtained by it to insure its directors and officers against personal liability for acts or omissions in connection with service as an officer or director of the Company or service in other capacities at the request of the Company. The coverage provided to Employee pursuant to this Section shall be of a scope and on terms and conditions at least as favorable as the coverage provided to Employee on the termination date of this Agreement.

16. Miscellaneous. No provision of this Agreement may be modified, waived or discharged unless such waiver, modification or discharge is agreed to in writing and signed by Employee and such officer as may be specifically authorized by the Board. No waiver by either party hereto at any time of any breach by the other party hereto of, or in compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. This Agreement is an integration of the parties agreement; no agreement or representations, oral or otherwise, express or implied, with respect to the subject matter hereof have been made by either party which are not set forth

expressly in this Agreement. The validity, interpretation, construction and performance of this Agreement shall be governed by the laws of the State of Delaware.

17. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original but all of which together will constitute one and the same instrument.

18. Arbitration. Employee shall be permitted (but not required) to elect that any dispute or controversy arising under or in connection with this Agreement be settled by arbitration in Denver, Colorado or in the city in which Employee then resides in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrator's award in any court having jurisdiction.

19. Prior Agreements. This agreement supersedes and replaces in full any previously existing employment agreement (written or oral) between the parties.

20. Knowledge of Terms and Conditions. Employee has received a copy of this Agreement in advance of his execution hereof and has consulted with his own attorney with respect to the terms and conditions hereof and the transactions contemplated under this Agreement. Employee has executed this Agreement with full knowledge of the terms and conditions contained herein and acknowledges that he has had the opportunity to obtain information regarding the Company and concerning the terms and conditions of this Agreement. In making his decision to enter into this Agreement, Employee has relied solely upon independent investigations he made and acknowledges that he is not relying on the Company, any affiliate of the Company or any officer, director or employee of the Company for advice with respect to any tax or other economic considerations involved in the transactions contemplated under this Agreement, including those arising under Section 409A of the Internal Revenue Code of 1986, as amended.

IN WITNESS WHEREOF, the parties have executed this Agreement effective for all purposes as of December 2011.

Venoco, Inc.

By: /s/ TIMOTHY M. MARQUEZ
Timothy M. Marquez
Chief Executive Officer

Employee

By: /s/ MARK DEPUY
Mark DePuy

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Exhibit 21.1

SUBSIDIARIES

Name of Company	Jurisdiction of Formation
Ellwood Pipeline, Inc.	California
Whittier Pipeline Corporation	Delaware
TexCal Energy (LP) LLC	Delaware
TexCal Energy (GP) LLC	Delaware
TexCal Energy South Texas L.P.	Texas

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (No. 333-166361) on Form S-3 and the Registration Statements (Nos. 333-159401 and 333-156116) on Form S-8 of our reports dated February 15, 2012, with respect to the consolidated financial statements of Venoco, Inc. and the effectiveness of internal control over financial reporting of Venoco, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2011.

/s/ ERNST & YOUNG LLP

Denver, Colorado
February 15, 2012

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Exhibit 23.3

DEGOLYER AND MACNAUGHTON
500 1 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244
February 14, 2012

Venoco, Inc.
370 17th Street
Suite 3900
Denver, Colorado 80202

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to the inclusion of our Letter Report, dated January 26, 2012, as attached as Exhibit 99.1 to the Annual Report on Form 10-K of Venoco, Inc., and to the inclusion of information from "Appraisal Report as of December 31, 2011 on Certain Properties owned by Venoco, Inc." "Appraisal Report as of December 31, 2010 on Certain Properties owned by Venoco, Inc.", and "Appraisal Report as of December 31, 2009 on Certain Properties owned by Venoco, Inc." (Our Reports) in the sections "Business and Properties," "Oil and Natural Gas Reserves," "Controls Over Reserve Report Preparation, Technical Qualifications and Technologies Used," and "Supplemental Information on Oil and Natural Gas Exploration, Development and Production Activities (Unaudited)" in the Annual Report on Form 10-K of Venoco, Inc. We also consent to the incorporation by reference of information from our Reports in the Registration Statements on Form S-3 (No. 333-166361) and Form S-8 (No. 333-159401) and Form S-8 (No. 333-156116).

Very truly yours,

/s/ DeGOLYER and MacNAUGHTON
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

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EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Timothy M. Marquez, certify that:

1. I have reviewed this report on Form 10-K of Venoco, Inc. ("Registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

/s/ TIMOTHY M. MARQUEZ

Timothy M. Marquez
Chief Executive Officer and Chairman
February 15, 2012

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Timothy A. Ficker, certify that:

1. I have reviewed this report on Form 10-K of Venoco, Inc. ("Registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this report;

4. The Registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the Registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter (the Registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting; and

5. The Registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

/s/ TIMOTHY A. FICKER

Timothy A. Ficker
Chief Financial Officer
February 15, 2012

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EXHIBIT 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Venoco, Inc. (the "Company"), on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ TIMOTHY M. MARQUEZ

Timothy M. Marquez
Chief Executive Officer and Chairman
February 15, 2012

/s/ TIMOTHY A. FICKER

Timothy A. Ficker
Chief Financial Officer
February 15, 2012

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Exhibit 99.1

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

January 26, 2012

Venoco, Inc.
370 17th Street
Suite 3900
Denver, Colorado 80202

Ladies and Gentlemen:

Pursuant to your request, we have conducted a reserves evaluation of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2011, of certain selected properties owned by Venoco, Inc. (Venoco). This evaluation was completed on January 26, 2012. The properties appraised consist of working and royalty interests located in the states of California and Texas. Venoco has represented that these properties account for 100 percent on a net equivalent barrel basis of Venoco's net proved reserves as of December 31, 2011. The net proved reserves estimates prepared by us have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States.

Reserves included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2011. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Venoco after deducting all interests owned by others.

Estimates of oil, condensate, NGL, and natural gas should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this evaluation were obtained from reviews with Venoco personnel, Venoco files, from records on file with the appropriate regulatory agencies, and from public sources. In the preparation of this report we have relied, without independent verification, upon such information furnished by Venoco with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Definition of Reserves

Petroleum reserves estimated by us included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* — Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> (i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves — Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves — Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil and Condensate Prices

Venoco has represented that the oil and condensate prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Venoco supplied differentials by field to a West Texas Intermediate reference price of $96.19 per barrel and the prices were held constant thereafter. The volume-weighted average price was $99.62 per barrel.

NGL Prices

Venoco has represented that the NGL prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Venoco supplied differentials by field to a reference price of $96.19 per barrel and the prices were held constant thereafter. The volume-weighted average price was $68.40 per barrel.

Natural Gas Prices

Venoco has represented that the natural gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The gas prices were calculated for each property using differentials to the Henry Hub reference price of $4.12 per Mcf furnished by Venoco and held constant thereafter. The volume-weighted average price was $4.052 per Mcf.

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Venoco, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. These costs were not escalated for inflation.

Abandonment costs, net of salvage, were provided by Venoco for certain properties. Venoco did not provide values for properties in which the abandonment costs were equal to, or offset by, the salvage values.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2011, estimated oil and gas volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

Our estimates of Venoco's net proved reserves attributable to the reviewed properties are based on the definitions of proved reserves of the SEC and are as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2011			
	Oil and Condensate (Mbbl)	**NGL (Mbbl)**	**Natural Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved Developed	24,070	1,062	141,806	48,766
Proved Undeveloped	20,401	1,881	149,019	47,119
Total Proved	**44,471**	**2,943**	**290,825**	**95,885**

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries — Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4—10(a) (1)—(32) of Regulation S—X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S—K of the Securities and Exchange Commission; provided, however, future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Venoco. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Venoco. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

/s/ DeGOLYER and MacNAUGHTON
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Paul J. Szatkowski, P.E.
Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Paul J. Szatkowski, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which company did prepare the letter report addressed to Venoco dated January 26, 2012, and that I, as Senior Vice President, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1974; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists; and that I have in excess of 37 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Paul J. Szatkowski, P.E.
Paul J. Szatkowski, P.E.
Senior Vice President
DeGolyer and MacNaughton

Exhibit 99.2

NON-EXCLUSIVE AIRCRAFT SUBLEASE AGREEMENT

THIS NON-EXCLUSIVE AIRCRAFT SUBLEASE AGREEMENT (this "**Agreement**") is made and entered into as of this 1st day of July, 2011, by and between TimBer, LLC, a limited liability company organized and existing under the laws of the State of Colorado ("**Sublessor**") and Venoco, Inc., a corporation organized and existing under the laws of the State of Delaware ("**Sublessee**") (each a "**Party**", and collectively the "**Parties**").

WITNESSETH:

WHEREAS, Sublessor has, pursuant to that certain Aircraft Lease dated as of December 29, 2010 (the "**Lease**") between Sublessor and Banc of America Leasing & Capital, LLC ("**Lessor**"), leased from Lessor one (1) Gulfstream Aerospace model G-IV (G300) aircraft bearing FAA registration number N958TB and manufacturer's serial number 1512 together with its two (2) Rolls-Royce Deutschland Ltd & Co KG model TAY 611-8 aircraft engines bearing manufacturer's serial numbers 18163 and 18164, its one (1) Honeywell International Inc. model GTCP-36-100 auxiliary power unit bearing manufacturer's serial number P-957, its avionics and equipment, optional equipment, such other items fitted or installed on the Aircraft and as more specifically described in the Lease and its Records (as defined in ***Schedule A***) (collectively, the "**Aircraft**"); and

WHEREAS, Sublessee desires to sublease the Aircraft from Sublessor on a non-exclusive basis; and

WHEREAS, Sublessor is willing to sublease the Aircraft to Sublessee on a non-exclusive basis on the terms and conditions contained herein.

NOW, THEREFORE, in consideration of the mutual covenants herein set forth, the parties agree as follows:

SECTION 1. ***SUBLEASE AND DELIVERY OF THE AIRCRAFT***

1.1 ***Sublease*.** Sublessor agrees to sublease to Sublessee, and Sublessee agrees to sublease from Sublessor, the Aircraft, on the terms and conditions of this Agreement.

1.2 ***Non-Exclusivity*.** Sublessee and Sublessor acknowledge that the Aircraft is subleased to Sublessee on a non-exclusive, non-continuous basis, and that the Aircraft may, at other times during the Term, be operated by Sublessor and/or subleased to other parties and under the operational control of such other parties during the Term.

(a) Sublessee specifically agrees that, to the extent permitted by the Lease, Sublessor may sublease the Aircraft to such other sublessees that may, during the periods of their possession, operate the Aircraft under Part 91 of the Federal Aviation Regulations ("**FARs**"), or to a certificated air carrier for operations under Part 135 of the FARs. At such times that the Aircraft is in the possession of Sublessor or such other sublessees, Sublessee shall not be in operational control of the Aircraft and shall have no responsibility for, or control over, the operation of the Aircraft, such operational control, responsibility and control residing solely with the party in possession of the Aircraft.

(b) Scheduling delivery periods of possession of the Aircraft shall be done by Sublessor on a first-come-first serve basis. If multiple requests for delivery of the Aircraft are made by Sublessee or other sublessees, such that not all the requests can be accommodated, the party making the first request shall have priority, the party making the second request shall have subsequent priority and so on and Sublessor shall deliver or arrange for delivery of the Aircraft to Sublessee or such other sublessees in the order described herein.

1.3 ***Delivery/Redelivery*.** The Aircraft shall be delivered to Sublessee at Centennial Airport, Denver, Colorado (the "**Operating Base**"), unless otherwise agreed to by the Parties, prior to each use of the Aircraft by Sublessee and, upon completion of each such use, redelivered to Sublessor or its agent as designated by Sublessor in writing at the Operating Base or such other location in the United States as agreed by the Parties in writing.

(a) Upon delivery or redelivery of possession of the Aircraft, as applicable, the Party receiving possession shall indicate its receipt of possession by executing a logbook (substantially in the form attached hereto as *Schedule B*) containing the information identifying the specific Party that has accepted possession and control of the Aircraft, the time such possession and control was accepted and the time the possession and control of the preceding party concluded ("**Delivery/Redelivery Logbook**"). The Delivery/Redelivery Logbook shall be kept with the Aircraft.

(b) Execution of the Delivery/Redelivery Logbook shall serve as evidence that the party accepting possession has assumed control and responsibility for the Aircraft until such time as it is again redelivered to Sublessor or its designee and the Delivery/Redelivery Logbook has been duly executed.

SECTION 2. ***TERM, SCHEDULING, AND RENT***

2.1 ***Term.*** This Agreement shall commence on the date of execution hereof and shall continue for a period of one (1) year. The term of the Agreement shall be renewed automatically thereafter for two (2) additional one (1) year terms, unless earlier terminated as set forth below. The initial term and any extension thereof shall be collectively referred to as the "**Term**". Notwithstanding anything to the contrary in this Section 2.1, this Agreement may be terminated by either party without cause upon at least thirty (30) days prior written notice to the other party; provided; however, in no case shall the Term extend beyond the term of the Lease unless Lessor notifies Sublessee of Lessor's election to permit Sublessee to continue to lease the Aircraft pursuant to this Agreement or Sublessor has purchased the Aircraft.

2.2 ***Rent.*** Sublessee shall pay rent in an amount equal to the Hourly Rent specified in **Schedule A** attached hereto for each block hour (choc off to choc on) of use of the Aircraft by Sublessee. All rent accrued during any calendar month shall be payable in arrears on the tenth (10^{th}) business day of next calendar month without further demand or invoice and accompanied by a report specifying the number of block hours operated by Sublessee in the preceding calendar month. Such report shall be in a form mutually agreed by the parties. All rent shall be paid to Sublessor in U.S. funds in the U.S. and in form and manner as Sublessor in its reasonable discretion may instruct Sublessee from time to time.

2.3 ***Taxes.*** Neither the Hourly Rent nor any other payments to be made by Sublessee under this Agreement includes the amount of any sales taxes, use taxes, retailer taxes, duties, fees or other taxes of any kind which may be assessed or levied by any taxing jurisdiction as a result of the sublease of the Aircraft to Sublessee, or the use of the Aircraft by Sublessee which may be assessed or levied by any taxing jurisdictions (the "**Taxes**"). Sublessee shall calculate or cause to be calculated the appropriate Taxes, if any, and remit to Sublessor all such Taxes together with and in addition to each payment of rent pursuant to Section 2.2 to the extent any such Taxes are due. Sublessor represents and warrants that it is responsible for all applicable sales and use taxes due on the Rent (as defined in the Lease) to be paid to Lessor under the Lease and covenants that it will pay such sales and use taxes during the Term hereof.

SECTION 3. ***DISCLAIMER OF WARRANTIES***

3.1 EXCEPT AS SPECIFICALLY SET FORTH IN THIS AGREEMENT, THE AIRCRAFT IS BEING SUBLEASED BY SUBLESSOR TO SUBLESSEE HEREUNDER ON AN "AS IS" BASIS. THE WARRANTIES AND REPRESENTATIONS SET FORTH IN THIS AGREEMENT ARE EXCLUSIVE AND IN LIEU OF ALL OTHER REPRESENTATIONS OR WARRANTIES, AND SUBLESSOR HAS NOT MADE AND SHALL NOT BE CONSIDERED OR DEEMED TO HAVE MADE AND SUBLESSEE HEREBY WAIVES, RELEASES, DISCLAIMS AND RENOUNCES ALL

EXPECTATION OF OR RELIANCE UPON ANY WARRANTIES, OBLIGATIONS AND LIABILITIES OF SUBLESSOR, EXPRESS, IMPLIED, ARISING BY LAW, COURSE OF DEALING, USAGE OF TRADE OR OTHERWISE, WITH RESPECT TO THE DESIGN, MERCHANTABILITY, OR FITNESS FOR A PARTICULAR USE OF THE AIRCRAFT.

3.2 NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR ANY INCIDENTAL, CONSEQUENTIAL, SPECIAL OR PUNITIVE DAMAGES (INCLUDING BUT NOT LIMITED TO STRICT OR ABSOLUTE LIABILITY IN TORT, LOST PROFITS OR REVENUES, OR DIMINUTION IN VALUE) ARISING FROM THE CONDITION, MAINTENANCE, USE, OPERATION, DELIVERY OR REDELIVERY OF THE AIRCRAFT.

3.3 THIS SECTION 3 SHALL SURVIVE THE EXPIRATION OR EARLIER TERMINATION OF THIS AGREEMENT.

SECTION 4. ***REGISTRATION, USE, OPERATION, MAINTENANCE AND POSSESSION***

4.1 ***Title and Registration*****.** Title to the Aircraft shall remain vested in Lessor at all times during the Term to the exclusion of Sublessee and Sublessee shall have only such leasehold rights as shall be specifically set forth herein. Sublessor represents that as of the date of this Agreement the Aircraft is, and Sublessor warrants that throughout the Term the Aircraft shall remain, lawfully registered as a civil aircraft of the United States.

4.2 ***Use and Operation by Sublessee*****.**

(a) Except as otherwise expressly provided herein, Sublessee shall be solely and exclusively responsible for the use, operation and control of the Aircraft during each period of the Term commencing when possession of the Aircraft has been delivered to Sublessee and terminating when possession of the Aircraft has been returned to Sublessor or its designee as evidenced in the Delivery/Redelivery Logbook. Sublessee shall operate the Aircraft in accordance with the provisions of Part 91 of the FARs and shall not operate the Aircraft in commercial service, as a common carrier, or otherwise on a compensatory or "for hire" basis except as specifically permitted under Part 91 of the FARs. Sublessee agrees not to operate the Aircraft or permit the Aircraft to be operated during the periods of Sublessee's possession during the Term except in operations for which Sublessee is duly authorized, or to use or permit the Aircraft to be used for a purpose for which the Aircraft is not designed or reasonably suitable. Sublessee will not use or operate the Aircraft contrary to any manufacturer's operating manuals or instructions, and during the periods of Sublessee's possession of the Aircraft during the Term shall not permit the Aircraft to be used during the existence of any known defect except as permitted by the FARs.

(b) Sublessee shall operate, use and locate the Aircraft solely within the Continental United States; *provided*, that Sublessee may fly the Aircraft temporarily to any country in the world for any purpose expressly permitted under this Agreement. Notwithstanding the foregoing, Sublessee shall not fly, operate, use or locate the Aircraft in, to or over any such country or area (temporarily or otherwise), (i) which is excluded from the required insurance coverages, or would otherwise cause Sublessee to be in breach of the insurance requirements or other provisions, of this Agreement; (ii) in any area of recognized or threatened hostilities; (iii) in violation of any Applicable Law, including any U.S. law or United Nations Security Council Directive; (iv) to the extent that payment of any claim under the insurance required hereunder directly or indirectly arising or resulting from or connected with any such flight, operation, use or location would be prohibited under any trade or other economic sanction or embargo by the United States of America; (v) with which the U.S. does not maintain favorable diplomatic relations; or (vi) in a manner that causes it to be deemed to have been used or operated "predominantly" outside of the United States of America, as that phrase is used in Section 168(g)(1)(A) of the Internal Revenue Code of 1986, as amended.

4.3 ***Operating Costs*****.** Except as otherwise provided herein, Sublessor shall pay all fixed and certain variable costs of operating the Aircraft, including, without limitation, all costs of insurance, hangarage and/or other storage costs in the Denver area, maintenance, inspections and overhauls. Sublessee shall, at its own expense, locate and retain (either through direct employment or contracting with an independent contractor for flight services) all pilots and other cabin personnel, if any, used for Sublessee's operations of the Aircraft (collectively the "**Flight Crew**"), and shall pay all fuel, oil and other lubricant costs and miscellaneous out-of-pocket expenses incurred in connection with Sublessee's use of the Aircraft, including, without limitation, landing and navigation fees; airport charges; catering, in-flight entertainment and communications charges; hangarage and/or other storage during Sublessee's period of use; Flight Crew travel expenses; and passenger service.

4.4 ***Maintenance of Aircraft.*** Sublessee shall perform, or cause to be performed, all customary pre- and post-flight inspections in accordance with and as required by the FAA-approved inspection program for the Aircraft. Sublessee shall notify Sublessor, or cause Sublessor to be notified, of any maintenance requirement, dangerous condition, malfunction or worn part of which Sublessee becomes aware as a result of such inspection. Subject to the foregoing, Sublessor shall be solely responsible for arranging the performance of all maintenance and inspections (other than pre- and post-flight inspections set forth in the first sentence of this Section 4.4) of the Aircraft and ensuring that all such maintenance and inspections are timely accomplished in accordance with the FARs during the Term. Sublessee shall make the Aircraft available in a timely manner to Sublessor or Sublessor's agent for any repair or maintenance requirements it discovers and Sublessor shall cause such maintenance or repairs to be timely and promptly performed. Sublessor shall not be held liable for any losses or damages incurred by Sublessee arising from delays resulting from or caused by the performance of all such maintenance and inspections required to be arranged by Sublessor; provided, however, that Sublessor shall cause all scheduled maintenance to be completed prior to the required compliance date and shall use its best efforts to cause all unscheduled maintenance to be diligently repaired so that the Aircraft can be returned to service as soon as possible. Sublessor shall ensure that Sublessee has complete and timely access to all Records.

4.5 ***Flight Crew*****.** All members of the Flight Crew shall be fully competent and experienced, duly licensed, and qualified in accordance with the requirements of Applicable Law and all insurance policies covering the Aircraft. Sublessee shall have full responsibility and authority for selecting the Flight Crew and Sublessor shall have no right to require Sublessee to use any particular flight crew or flight crew company or to veto the use of any particular flight crew or flight crew company. Without limiting the generality of the foregoing, the pilots shall have (a) the required FAA pilot certificates and ratings, (b) a valid FAA Medical Certificate, (c) satisfied all security requirements imposed by any governmental authority having jurisdiction and (d) met any and all other requirements established and specified by (i) the FAA, the Transportation Security Administration and any other applicable governmental authority and (ii) the insurance policies required under this Agreement.

4.6 ***Operational Control*****.** THE PARTIES EXPRESSLY AGREE THAT SUBLESSEE SHALL AT ALL TIMES WHILE THE AIRCRAFT IS IN ITS POSSESSION DURING THE TERM MAINTAIN OPERATIONAL CONTROL OF THE AIRCRAFT, AND THAT THE INTENT OF THE PARTIES IS THAT THIS AGREEMENT CONSTITUTE A "DRY" OPERATING SUBLEASE. Sublessee shall exercise exclusive authority over initiating, conducting, or terminating any flight conducted pursuant to this Agreement, and the Flight Crew shall be under the exclusive command and control of Sublessee during all phases of such flights. Sublessee shall be liable for the actions or inactions of the Flight Crew during all phases of such flights.

4.7 ***Authority of Pilot-in-Command*****.** Notwithstanding that Sublessee shall have operational control of the Aircraft during all flights conducted by Sublessee pursuant to this Agreement, Sublessor and Sublessee expressly agree that the pilot in command (as defined in section 1.1 of the FARs), in his or her sole discretion, may terminate any flight, refuse to commence any flight, or take any other flight-related action which in the judgment of the pilot-in-command is necessitated by considerations of safety. The pilot-in-command shall have final and complete authority to postpone or cancel any flight for any reason or condition which in his or her judgment would compromise the safety of the flight. No such action of the pilot in command shall create or support any claim for liability for loss, injury, damage or delay by Sublessor.

4.8 ***Security.*** Without limiting Sublessee's other obligations under this Agreement, Sublessee hereby: (i) expressly assumes responsibility for the determination and implementation of all security measures and systems necessary or appropriate for the proper protection of the Aircraft (whether on the ground or in flight) against theft, vandalism, hijacking, destruction, bombing, terrorism or similar acts directly or indirectly affecting the Aircraft, any part thereof, or any persons who (whether or not on board the Aircraft) may sustain any injury or damage as a result of any such acts, while Sublessee has possession of the Aircraft during the periods of its possession during the Term; and (ii) agrees to provide to Sublessor promptly upon request evidence of Sublessee's compliance with its obligations under this Section 4.8.

4.9 ***Right to Inspect.*** Sublessor, Lessor and their respective agents shall have the right to inspect the Aircraft, any component thereof, and all logs, manuals, certificates and records with respect thereto at any reasonable time, upon giving Sublessee reasonable notice, to ascertain the condition of the Aircraft and to ensure that the Aircraft is being properly operated, repaired and maintained in accordance with the requirements of this Agreement; except that no advance notice shall be necessary prior to any inspection conducted, and such inspection may be conducted at any time, after the occurrence of an Event of Default. Upon request of Lessor or Sublessor, Sublessee shall promptly confirm to Lessor or Sublessor, as the case may be, the location of the Aircraft and/or such logs, manuals, certificates and records as are under Sublessee's control. Sublessee shall be responsible for the cost of any inspection conducted after the occurrence of an Event of Default by Sublessee under this Agreement. For the avoidance of doubt, Sublessee shall not be responsible for the cost of any inspection conducted by Lessor after the occurrence of any Event of Default under the Lease (as defined therein), such cost to be borne solely by Sublessor. When there has been no occurrence of an Event of Default, the right of inspection shall be exercised in such manner as shall not interfere with the normal conduct of Sublessee's business or the operation of the Aircraft.

SECTION 5. ***CONDITION DURING TERM AND RETURN OF AIRCRAFT.*** Upon completion of each use of the Aircraft by Sublessee during the Term, Sublessee shall return the Aircraft to Sublessor or its representative in as good condition as at it was in when Sublessor or its designee delivered or caused the Aircraft to be delivered to Sublessee, ordinary wear and tear excepted, and shall have a valid and effective FAA standard airworthiness certificate. Nothing contained in this Section 5 may be interpreted to require Sublessee to perform any maintenance or other obligation responsibility for which is delegated to Sublessor pursuant to this Agreement; provided, however, that Sublessee shall be obligated to ensure that Sublessor or its agent is advised of any maintenance requirement, dangerous condition, malfunction or worn part of which Sublessee actually becomes aware during the customary pre- and post-flight inspections conducted by Sublessee or during its operation of the Aircraft.

SECTION 6. ***LIENS.*** Sublessee shall ensure that no liens are created or placed against the Aircraft by Sublessee or third parties as a result of Sublessee's or its agents' or representatives' action or inaction except for Permitted Liens as defined by the Lease, which definition shall be deemed to refer to Sublessee as well as Lessee ("**Permitted Liens**").

SECTION 7. ***EVENTS OF DEFAULT AND REMEDIES.***

7.1 ***Events of Default.*** The term "**Event of Default**" means: (i) non-payment of any Hourly Rent and/or any other amount due pursuant to this Agreement within ten (10) days after any or all of the same shall become due and payable, or, upon demand, any other amount required to be paid herein; (ii) failure by Sublessee to use, or operate the Aircraft in compliance with Applicable Law; (iii) any use by Sublessee of the Aircraft outside of the U.S. that is prohibited by this Agreement, or use by Sublessee for any illegal purpose; (iv) failure by Sublessee to comply with all of the insurance coverages required under this Agreement when it is in possession of the Aircraft; (v) any prohibited transfer or encumbrance, or the existence of any lien caused by an act or omission of Sublessee other than a Permitted Lien where the obligation for payment is vested in Sublessee hereunder; (vi) failure to return the Aircraft to Sublessor, or other sublessee as applicable, in the manner required by this Agreement; (vii) a material inaccuracy in any representation or breach of warranty by Sublessee (including any false or misleading representation or warranty); (viii) the commencement of any bankruptcy, insolvency, receivership or similar proceeding by or against Sublessee or any of its properties or business (unless, if involuntary, the proceeding is dismissed within sixty (60) days of the filing thereof) or the rejection of this Agreement in any such proceeding; or (ix) the failure by Sublessee generally to pay Sublessee's debts as they become due or Sublessee's admission in writing of such inability.

7.2 ***Remedies***. If an Event of Default occurs which is continuing and not cured within any applicable cure period, Sublessor or Lessor may exercise any one or more of the following remedies (each in its sole discretion): (i) proceed at law or in equity, to enforce specifically Sublessee's performance or to recover damages; (ii) declare this Agreement in default, and/or cancel this Agreement or otherwise terminate Sublessee's right to use of the Aircraft and Sublessee's other rights, but not its obligations under this Agreement, and Sublessee shall immediately return the Aircraft to Sublessor in accordance with the terms of this Agreement; (iii) to the extent permitted by Applicable Law, enter the premises where the Aircraft is located and take immediate possession of and remove (or disable in place) the Aircraft (and/or any engine, APU or part then unattached to the Aircraft) by self-help, summary proceedings or otherwise without liability; (iv) demand and obtain from any court speedy relief pending final determination available at law (including, without limitation, possession, control, custody or immobilization of the Aircraft or preservation of the Aircraft or its fair market value); and (v) exercise any and all other remedies allowed by Applicable Law, including, without limitation, the Cape Town Convention and the UCC.

7.3 ***Sublessee's Performance***. If Sublessee fails to perform any of its agreements contained in this Agreement, including its obligations to keep the Aircraft free of liens or comply with Applicable Law Sublessor shall have the right, but shall not be obligated, to effect such performance upon five (5) days notice to Sublessee, and any expenses incurred by Sublessor in connection with effecting such performance, shall be payable by Sublessee promptly upon demand. Any such action shall not be a cure or waiver of any Event of Default hereunder.

7.4 ***Power-of-Attorney***. Sublessee irrevocably appoints Sublessor as its attorney-in-fact to act in Sublessee's name and on its behalf to make, execute, deliver and file any instruments or documents (including any filings at the FAA), settle, adjust, receive payment, make claim or proof of loss, endorse Sublessee's name on any checks, drafts or other instruments in payment of any insurance claims and to take any action as Sublessor deems necessary or appropriate to carry out the intent of this Agreement; *provided, however*, Sublessor agrees that it will not exercise this power unless an Event of Default has occurred and is continuing. This appointment is coupled with an interest, is irrevocable, and shall terminate only upon payment in full of the obligations set forth in this Agreement.

7.5 ***Enforcement Costs***. Sublessee shall be liable for, and pay to Sublessor upon demand, all reasonable and documented costs, charges and expenses incurred by Sublessor in enforcing or protecting its rights under this Agreement by reason of any Event of Default which is continuing and not cured, including, without limitation, legal fees and disbursements.

7.6 ***Cumulative Remedies*.** No right or remedy is exclusive. Sublessee hereby acknowledges that none of the provisions of this Section 7, including any remedies set forth or referenced herein, is "manifestly unreasonable" for the purposes of the Cape Town Convention. Each may be used successively and cumulatively and in addition to any other right or remedy referred to above or otherwise available at law or in equity, including, such rights and/or remedies as are provided for in the Cape Town Convention and/or the UCC, but in no event shall Sublessor be entitled to recover any amount in excess of the maximum amount recoverable under Applicable Law with respect to any Event of Default. No express or implied waiver by Lessor or Sublessor of any Event of Default hereunder shall in any way be, or be construed to be, a waiver of any future or subsequent Event of Default. The failure or delay of Sublessor in exercising any rights granted it hereunder upon the occurrence of any of the contingencies set forth herein shall not constitute a waiver of any such right upon the continuation or reoccurrence of any such contingencies or similar contingencies, and any single or partial exercise of any particular right by Sublessor shall not exhaust the same or constitute a waiver of any other right provided for or otherwise referred to herein. Sublessee hereby waives any rights under the UCC and/or the Cape Town Convention to cancel or repudiate this Agreement or any of the other Lease Documents, to suspend performance, and to recover from Sublessor any general, special, incidental or consequential damages, for any reason whatsoever. All remedies set forth herein shall survive the expiration, cancellation or other termination of this Agreement for any reason whatsoever.

SECTION 8. ***EVENTS OF LOSS***

8.1 ***Event of Loss with Respect to the Aircraft*.** Upon the occurrence of any Event of Loss (as defined in *Schedule A* herein) with respect to the Aircraft, Sublessee shall notify Sublessor within five (5) days of the date thereof. Upon making the notice required hereby, Sublessee is obligated to pay all Hourly Rents then accrued but unpaid.

8.2 ***Risk of Loss*.** Sublessee shall bear the risk of loss, theft, confiscation, taking, unavailability, damage or partial destruction of the Aircraft during the time Sublessee has possession of the Aircraft during the Term and Sublessee shall not be released from its obligations hereunder in the event of any damage or Event of Loss to the Aircraft or any part thereof; provided, however, that Sublessor agrees to accept, as its sole remedy, the proceeds of the insurance provided under Section 9.2 except to the extent such loss, theft, confiscation, taking, unavailability, damage or partial destruction of the Aircraft resulted solely and directly from the willful misconduct of Sublessee. Without limiting any other provision hereof, Sublessee shall provide written notice to Sublessor of any material damage concurrently with its report of same to the applicable governmental authority, and if no such report is required, within ten (10) days of the occurrence of such damage. The required notice must be provided together with any damage reports provided to the FAA or any other governmental authority or the insurer, and, to the extent Sublessee has such documents, any documents pertaining to the repair of such damage, including copies of work orders, and all invoices for related charges.

SECTION 9. ***INSURANCE***

9.1 ***Liability*.** Sublessor shall maintain, or cause to be maintained, bodily injury and property damage, liability insurance in an amount no less than Two Hundred Million United States Dollars (US$200,000,000) combined single limit for the benefit of itself and Sublessee in connection with the use of the Aircraft. Said policy shall be an occurrence policy and shall include Sublessee and its officers, directors, managers and employees as an additional named insureds.

9.2 ***Hull*.** Sublessor shall maintain aircraft hull insurance in such amount as is required by the Lease. Said policy shall contain a waiver of subrogation clause in favor of Sublessee.

9.3 ***Insurance Certificates*.** Sublessor will provide or cause Sublessee to be provided with a copy of the insurance policy, the applicable endorsements and a certificate of insurance upon execution of this Agreement and thereafter reasonably upon request therefor.

9.4 ***Required Provisions***. Each insurance policy required hereunder shall insure the interest of Sublessee regardless of any breach or violation by Sublessor, any other sublessee or any other party of any warranties, declarations, or conditions contained in such policies. Each such policy shall be primary without any right of contribution from any insurance maintained by Sublessor, Sublessee, any other sublessee or any other party. Each policy shall contain an agreement by the insurer that, notwithstanding the lapse of any such policy for any reason or any right of cancellation by the insurer or Lessor or Sublessor, whether voluntary or involuntary, such policy shall continue in force for the benefit of Sublessee for at least thirty (30) days ((ten (10) days for cancellation for nonpayment) or such lesser time as may be permitted in the case of war risk insurance, if such war risk insurance so requires) after written notice of such lapse or cancellation shall have been given to Sublessee. Each policy shall contain an agreement by the Insurer to provide Sublessee with thirty (30) days' advance written notice of any deletion, cancellation, or material change in coverage. Sublessee shall be provided with the benefit of all coverage and endorsements contained in the policy and made available to Lessor and Sublessor except such coverage as is available only to an owner or lessor of the Aircraft.

9.5 ***Underwriter***. Each insurance policy required hereunder shall be issued by a company or companies qualified to do business in the United States and that (i) will submit to the jurisdiction of any competent state or federal court in the United States with regard to any dispute arising out of the policy of insurance or concerning the parties herein; and (ii) will respond to any claim or judgment against Sublessee in any competent state or federal court in the United States or its territories.

SECTION 10. ***NOTICES.*** All notices and other communications required or permitted by this Agreement shall be in writing and shall be deemed to have been duly given or made upon actual receipt or refusal to accept receipt when delivered personally, by mail, by a courier service that provides delivery receipts, or by facsimile that provides confirmation of delivery of all of the pages of such notice or communication provided that any facsimile delivered after 5 pm local time at the location of the recipient shall be deemed to have been delivered on the next business day in the location of the recipient). No objection may be made to the manner of delivery of any notice actually received in writing by an authorized agent of a party. Notices shall be addressed as specified in writing by the relevant party from time to time and shall initially be as follows:

If to Sublessor:	**TimBer, LLC**	Tel: 303-600-2896
	PO Box 44354	Fax: 303-626-8315
	Denver, CO 80201	
	Attn: David Mokros	
If to Sublessee:	**Venoco, Inc.**	Tel: 303-600-2846
	370 17th Street, Suite 3900	Fax: 303-626-2992
	Denver, CO 80202-1370	
	Attn: Timothy A. Ficker	

SECTION 11. ***MISCELLANEOUS***

11.1 ***Entire Agreement***. This Agreement, and all terms, conditions, warranties, and representations herein, are for the sole and exclusive benefit of the signatories hereto and the Lessor as per the terms of the Consent to Sublease and Assignment. This Agreement, together with the Consent to Sublease and Assignment constitute the entire agreement of the parties as of its effective date and supersedes all prior or independent, oral or written agreements, understandings, statements, representations, commitments, promises, and warranties made with respect to the subject matter of this Agreement.

11.2 ***Other Transactions***. Except as specifically provided in this Agreement, none of the provisions of this Agreement, nor any oral or written statements, representations, commitments, promises, or warranties made with respect to the subject matter of this Agreement shall be construed or relied upon by any party as the basis of, consideration for, or inducement to engage in, any separate agreement, transaction or commitment for any purpose whatsoever.

11.3 ***Prohibited and Unenforceable Provisions.*** Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibitions or unenforceability in any jurisdiction. To the extent permitted by applicable law, each of Sublessor and Sublessee hereby waives any provision of applicable law which renders any provision hereof prohibited or unenforceable in any respect.

11.4 ***Enforcement.*** This Agreement, including all agreements, covenants, representations and warranties, shall be binding upon and inure to the benefit of, and may be enforced by Sublessor, Sublessee, and their successors and assigns.

11.5 ***Headings.*** The section and subsection headings in this Agreement are for convenience of reference only and shall not modify, define, expand, or limit any of the terms or provisions hereof.

11.6 ***Counterparts.*** This Agreement may be executed by the parties hereto in separate counterparts, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute but one and the same instrument.

11.7 ***Amendments.*** No term or provision of this Agreement may be amended, changed, waived, discharged, or terminated orally, but only by an instrument in writing signed by the party against which the enforcement of the change, waiver, discharge, or termination is sought.

11.8 ***No Waiver.*** No delay or omission in the exercise or enforcement or any right or remedy hereunder by either party shall be construed as a waiver of such right or remedy. All remedies, rights, undertakings, obligations, and agreements contained herein shall be cumulative and not mutually exclusive, and in addition to all other rights and remedies which either party possesses at law or in equity.

11.9 ***No Assignments or Subleases.*** Sublessee shall not without the prior written consent of Sublessor and Lessor or as otherwise permitted herein (i) assign any of its rights or obligations or delegate any of its duties under this Agreement or (ii) sublease or otherwise in any manner deliver, transfer or relinquish operational control and possession of the Aircraft except for such incidental transfers of possession as may occur in the ordinary course of operating the Aircraft, including but not limited to possession by a duly qualified aircraft manager used by Sublessee, hangarkeeper and similar parties.

11.10 ***Governing Law; Jurisdiction.*** BOTH PARTIES AGREE THAT THIS LEASE SHALL BE CONSTRUED AND ENFORCED IN ACCORDANCE WITH, AND THE RIGHTS OF BOTH PARTIES SHALL BE GOVERNED BY, THE INTERNAL LAWS OF THE STATE OF NEW YORK (WITHOUT REGARD TO THE CONFLICT OF LAWS PRINCIPLES OF SUCH STATE, OTHER THAN SECTIONS 5-1401 AND 5-1402 OF THE NEW YORK GENERAL OBLIGATIONS LAW), INCLUDING ALL MATTERS OF CONSTRUCTION, VALIDITY, AND PERFORMANCE. Sublessee hereby irrevocably consents and agrees that any legal action, suit, or proceeding arising out of or in any way in connection with this Agreement may be instituted or brought in the courts of the State of New York or the U.S. District Court for the Southern District of New York, as Sublessor may elect, and by execution and delivery of this Agreement, Sublessee hereby irrevocably accepts and submits to, for itself and in respect of its property, generally and unconditionally, the non-exclusive jurisdiction of any such court, and to all proceedings in such courts. Notwithstanding anything in the foregoing to the contrary, the parties may bring a judicial proceeding against the registrar of the International Registry in the Republic of Ireland, solely with respect to matters relating to the International Registry itself. SUBLESSEE ALSO HEREBY KNOWINGLY AND FREELY WAIVES

ALL RIGHTS TO TRIAL BY JURY IN ANY LITIGATION ARISING HEREFROM OR IN RELATION HERETO

11.11 ***Quiet Enjoyment.*** Sublessor warrants that during the Term, so long as no Event of Default has occurred and is continuing, Sublessee's periods of possession and use of the Aircraft shall not be interfered with by Sublessor or anyone rightfully claiming an interest through Sublessor.

11.12 ***Subordination.*** The rights of Sublessee (and of any party claiming through Sublessee) with respect to the Aircraft shall be subject and subordinate in all respects to Lessor's rights, title and interests in the Aircraft, including all of Lessor's rights and remedies under the Lease and the other documents relating thereto as more fully set forth in that certain Consent to Sublease and Assignment executed by Lessor, Sublessor and Sublessee of even date herewith.

[Remainder of Page Intentionally Left Blank]

SECTION 12. ***TRUTH IN LEASING*** STATEMENT UNDER SECTION 91.23 OF THE FARs.

(a) SUBLESSOR HEREBY CERTIFIES THAT THE AIRCRAFT HAS BEEN INSPECTED AND MAINTAINED WITHIN THE 12 MONTH PERIOD PRECEDING THE DATE OF THIS AGREEMENT (EXCEPT TO THE EXTENT SUBLESSOR HAS HAD THE AIRCRAFT FOR LESS THAN 12 MONTHS IN WHICH CASE SUCH CERTIFICATION COVERS ONLY THE PERIOD FOLLOWING SUBLESSOR'S ACQUISITION OF THE AIRCRAFT) IN ACCORDANCE WITH THE PROVISIONS OF FAR PART 91 AND ALL APPLICABLE REQUIREMENTS FOR THE MAINTENANCE AND INSPECTION THEREUNDER HAVE BEEN MET.

(b) THE PARTIES HERETO CERTIFY THAT DURING THE TERM OF THIS AGREEMENT AND FOR OPERATIONS CONDUCTED HEREUNDER, THE AIRCRAFT WILL BE MAINTAINED AND INSPECTED IN ACCORDANCE WITH THE PROVISIONS OF PART 135 OF THE FARs.

(c) SUBLESSEE AGREES, CERTIFIES AND KNOWINGLY ACKNOWLEDGES THAT WHEN THE AIRCRAFT IS OPERATED UNDER THIS AGREEMENT, SUBLESSEE SHALL HAVE OPERATIONAL CONTROL AND SHALL BE KNOWN AS, CONSIDERED, AND SHALL IN FACT BE THE OPERATOR OF THE AIRCRAFT. SUBLESSEE CERTIFIES THAT IT UNDERSTANDS THE EXTENT OF ITS RESPONSIBILITIES, SET FORTH HEREIN, FOR COMPLIANCE WITH APPLICABLE FEDERAL AVIATION REGULATIONS.

(d) THE PARTIES UNDERSTAND THAT AN EXPLANATION OF FACTORS AND PERTINENT FEDERAL AVIATION REGULATIONS BEARING ON OPERATIONAL CONTROL CAN BE OBTAINED FROM THE LOCAL FAA FLIGHT STANDARDS DISTRICT OFFICE, GENERAL AVIATION DISTRICT OFFICE or AIR CARRIER DISTRICT OFFICE).

(e) SUBLESSEE CERTIFIES THAT IT WILL SEND A TRUE COPY OF THIS EXECUTED AGREEMENT TO: AIRCRAFT REGISTRATION BRANCH, ATTN: TECHNICAL SECTION, P.O. BOX 25724, OKLAHOMA CITY, OKLAHOMA, 73125, WITHIN 24 HOURS OF ITS EXECUTION, AS PROVIDED BY FAR 91.23(c)(1) AND THAT A TRUE COPY OF THIS AGREEMENT SHALL BE CARRIED ON THE AIRCRAFT AT ALL TIMES, AND SHALL BE MADE AVAILABLE FOR INSPECTION UPON REQUEST BY AN APPROPRIATELY CONSTITUTED IDENTIFIED REPRESENTATIVE OF THE ADMINISTRATOR OF THE FAA.

(f) SUBLESSEE CERTIFIES THAT IT WILL NOTIFY, BY TELEPHONE OR IN PERSON, THE FAA FLIGHT STANDARDS DISTRICT OFFICE NEAREST THE AIRPORT WHERE THE FIRST FLIGHT UNDER THIS AGREEMENT WILL ORIGINATE WITHIN 48 HOURS BEFORE TAKEOFF OF THAT FIRST FLIGHT AND INFORM THE FAA OF THE LOCATION OF THE AIRPORT OF DEPARTURE, THE DEPARTURE TIME, AND THE REGISTRATION NUMBER OF THE AIRCRAFT.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, Sublessor and Sublessee have each caused this **Non-Exclusive Aircraft Sublease Agreement** to be duly executed as of the date set forth above.

SUBLESSOR: TIMBER, LLC		**SUBLESSEE:** VENOCO, INC.	
By:	/s/ DAVID MOKROS	By:	/s/ TIMOTHY A. FICKER
Name:	David Mokros	Name:	Timothy A. Ficker
Title:	*Manager*	Title:	*Chief Financial Officer*

NON-EXCLUSIVE AIRCRAFT SUBLEASE AGREEMENT:

Schedule A

Applicable Law: Applicable Law shall mean all applicable laws including all statutes, treaties, conventions, judgments, decrees, injunctions, writs and orders of any court, governmental agency or authority and rules, regulations, orders, directives, licenses and permits of any governmental body, instrumentality, agency or authority as amended and revised from time to time, and any judicial or administrative interpretation, of any of the same, including, without limitation, the airworthiness certificate issued with respect to the Aircraft, the Cape Town Convention, all FARs, airworthiness directives, and/or any of the same relating to noise, the environment, national security, public safety, exports or imports or contraband.

Hourly Rent: Five Thousand Six Hundred US Dollars ($5,600) per block hour.

Records: The original versions of any and all logs, manuals, certificates and data and inspection, modification, maintenance, engineering, technical, and overhaul records (whether in written or electronic form) with respect to the Aircraft, including, without limitation, (i) all records required to be maintained by the FAA or any other governmental agency or authority having jurisdiction with respect to the Aircraft or by any manufacturer or supplier of the Aircraft (or any part thereof) with respect to the enforcement of warranties or otherwise, and (ii) with respect to the airframe, any engine, APU or any part, all records related to any manufacturer's maintenance service program or any computerized maintenance monitoring program or engine maintenance program, which Records shall be at all times the property of the owner of the Aircraft.

Event of Loss: Event of Loss with respect to the Aircraft, the airframe or any engine or APU, shall mean any of the following events with respect to such property when in the possession of Sublessee (i) loss of such property or the use thereof due to theft, disappearance, destruction, damage beyond repair or rendition of such property permanently unfit for normal use for any reason whatsoever; (ii) any damage to such property when in the possession of Sublessee which results in an insurance settlement with respect to such property on the basis of a total loss or constructive total loss; (iii) the condemnation, confiscation or seizure of, or requisition of title to or use of, such property by the act of any government (foreign or domestic) or of any state or local authority or any instrumentality or agency of the foregoing when in the possession of Sublessee ("*Requisition of Use*"); or (vi) The date of such Event of Loss shall be the date of such theft, disappearance, destruction, damage or Requisition of Use. An Event of Loss with respect to the Aircraft shall be deemed to have occurred if an Event of Loss occurs with respect to the airframe. An Event of Loss with respect to any engine or APU shall not, without loss of the airframe, be deemed an Event of Loss with respect to the Aircraft.

NON-EXCLUSIVE AIRCRAFT SUBLEASE AGREEMENT

Schedule B
Delivery/Redelivery Logbook

Gulfstream Aerospace model G-IV (G300) aircraft
FAA registration number N958TB
Manufacturer's serial number 5092

Name of Party Accepting Delivery	Acceptance Date, Time, and Signature:	Total Block Hours Since Acceptance of Delivery Prior to Redelivery	Name Of Party to Whom Aircraft is Redelivered and Date and Time of Redelivery.
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:
	Date: Time: Signature:		Name: Date: Time:

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