SWIFT ENERGY CO
Form 10-K
February 24, 2011

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, 2010

Commission File Number 1-8754

SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

TEXAS	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class	Exchanges on Which Registered:
Common Stock, par value $.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.
YesþNo

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.
Yes No þ

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, and (2) has been subject to such filing requirements for the past 90 days.
Yes þ 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. [þ]

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

Large accelerated filer þ	Accelerated filer	Non-accelerated filer

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold on the New York Stock Exchange as of June 30, 2010, the last business day of June 2010, was approximately $1,019,313,879.

The number of shares of common stock outstanding as of January 31, 2011 was 42,049,082.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 10, 2011	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 10, 2011

PART I

Items 1 and 2. Business and Properties

See pages 25 and 26 for explanations of abbreviations and terms used herein.

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and natural gas properties, with a focus on oil and natural gas reserves in Texas as well as onshore and in the inland waters of Louisiana. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. At year-end 2010, we had estimated proved reserves from our continuing operations of 132.8 MMBoe with a PV-10 of $1.8 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). Our total proved reserves at year-end 2010 were approximately 30% crude oil, 53% natural gas, and 17% NGLs; and 45% of our total proved reserves were proved developed. Our proved reserves are concentrated with 40% in Louisiana and 59% in Texas.

We currently focus primarily on development and exploration of four core areas. The major fields in our core areas are:

- South Texas
  - Olmos
    - AWP
    - Sun TSH
    - Las Tiendas
  - Eagle Ford
    - Hawkville AWP
    - Hawkville Artesia Wells
    - Hawkville Fasken
- Southeast Louisiana
  - Lake Washington
  - Bay de Chene
- Central Louisiana/East Texas
  - Brookeland
  - South Bearhead Creek
  - Masters Creek
  - Burr Ferry
- South Louisiana
  - Horseshoe Bayou/Bayou Sale
  - Jeanerette
  - Cote Blanche Island

Competitive Strengths and Business Strategy

Our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to achieve our goals. Our primary strengths and strategies are set forth below.

Demonstrated Ability to Grow Reserves and Production

We have grown our proved reserves from 107.3 MMBoe to 132.8 MMBoe over the five-year period ended December 31, 2010. Over the same period, our annual production has grown from 7.2 MMBoe to 8.3 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities and acquisitions in our core areas. During 2010, our proved reserves increased by 18%, due mainly to additional drilling in our South Texas core area. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to continue growing both our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions and strategic opportunities. In general, we use acquisitions to gain entry into new core areas and then increase reserves and production through development and exploratory activities within these areas. Through our strategic growth initiatives we target locations outside of our core areas for new exploration opportunities. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. We have replaced 154% of our production on average over the last five years.

We currently plan to balance our 2011 capital expenditures with our 2011 cash flow, cash on hand and potential line of credit borrowings. Our 2011 capital expenditures are currently budgeted at $430 million to $480 million, net of potential dispositions of non-strategic properties. Approximately 80% of our capital budget is targeted for our South Texas core area. The Company may also explore both joint venture arrangements for particular prospects and select property dispositions, in each case to accelerate drilling and development of its assets and diversify its risk profile. For 2011, are targeting an increase in production volumes of 25% to 30% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Replacement of Reserves

Historically we have added proved reserves through both our drilling and acquisition activities. We believe that this strategy will continue to add reserves for us over the long-term; however, external factors beyond our control, such as limited availability of capital or its cost, competition within our industry, adverse weather conditions, commodity market factors, the requirement of new or upgraded infrastructure at the production site, technological advances, and governmental regulations, could limit our ability to drill wells, access reserves, and acquire proved properties in the future. We have included a listing of the vintages of our proved undeveloped reserves in the table titled “Proved Undeveloped Reserves” and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and natural gas production. Our reserves additions for each year are estimates. Reserves volumes can change over time and therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated.

Concentrated Focus on Core Areas with Operational Control

The concentration of our operations in our core areas allows us to leverage our drilling unit and workforce synergies while minimizing the continued escalation of drilling and completion costs. Our average lease operating costs for continuing operations, excluding taxes, were $9.84, $8.47 and $10.44 per Boe in 2010, 2009, and 2008, respectively. Each of our core areas includes properties that are targeted for future growth. This concentration allows us to utilize the experience and knowledge we gain in these areas to continually improve our operations and guide us in developing our future activities and in operating similar types of assets. The value of this concentration is enhanced by our operational control of 93% of our proved oil and natural gas reserves base as of December 31, 2010. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital, and time field development.

Develop Under-Exploited Properties

We are focused on applying advanced technologies and recovery methods to areas with known hydrocarbon resources to optimize our exploration and exploitation of such properties as illustrated in our core areas. For instance, in 1989 we acquired producing properties in the AWP field in McMullen County, TX from a major producer. This field had been developed in the early 1980’s and was considered close to maturity when we made this acquisition. The Company began to acquire adjacent undeveloped acreage and in 1994 launched an aggressive drilling program. This area has remained a cornerstone of our operations as we have pursued other opportunities. Since assuming operations in this area, our drilling and completion techniques have been continuously refined to improve hydrocarbon recovery from the tight sand Olmos formation. Almost all of our existing interest overlays portions of the now very active Eagle Ford shale play which is being developed through the combination of horizontal drilling and multi-stage fracture stimulation completion techniques. While the combination of proven drilling and completion technologies have allowed us to begin to exploit the Eagle Ford shale, we have applied the same methods to further develop the "mature" Olmos sand. As a result we substantially increased our Olmos production and reserves during 2010 even though we have been producing from this formation for over 20 years. The Company has acquired 750 square miles of 3D seismic data over the AWP Field. We began merging and prestack time migrating this data into a continuous data set that we are using to plan our wells and enhance and expand our developments. Another of our significant successes is the Lake Washington field. This field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily net production from less than 700 Boe to a peak of over 18,000 Boe. We have utilized enhanced 3-D seismic and various completion techniques including sliding sleeves to improve drilling success and production performance. When we acquired this field we booked 7.7 MMBoe of reserves. Since acquisition we produced 45 MMBoe and still have remaining proved reserves of 17.7 MMBoe. In October 2007, we acquired interests in two South Texas properties in the Gulf Coast basin (Sun TSH and Las Tiendas) which, along with AWP, have acreage prospective for Eagle Ford shale development. These properties are located in the Sun TSH field in La Salle County and the Las Tiendas field in Webb County. We intend to continue acquiring large acreage positions where we can grow production by applying advanced technologies and recovery methods using our experience and knowledge developed in our core areas.

Maintain Financial Flexibility and Disciplined Capital Structure

We practice a disciplined approach to financial management and have historically maintained a disciplined capital structure to provide us with the ability to execute our business plan. As of December 31, 2010, our debt to capitalization was approximately 35%, while our debt to proved reserves ratio was $3.55 per Boe, and our debt to PV-10 ratio was 25%. We plan to maintain a capital structure that provides financial flexibility through the prudent use of capital, aligning our capital expenditures to our cash flows, and maintaining a strategic hedging program when appropriate.

Experienced Technical Team and Technology Utilization

We employ 64 oil and gas technical professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers, who have an average of approximately 25 years of experience in their technical fields and have been employed by us for an average of approximately six years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other related services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We increasingly use advanced technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, licensing and pre-stack time and depth imaging, advanced attributes, pore-pressure analysis, inversion and detailed field reservoir depletion planning. In 2004, we recorded a 3-D seismic survey covering our Lake Washington field, and in 2006 we recorded a second 3-D survey in and around our Cote Blanche Island field. We now have proprietary pre-stack time and depth migrated seismic data covering over 4,000 square miles in South Louisiana. These data have been merged into two large data volumes, inclusive of data covering five fields we acquired in 2006. In late 2007, we began to extend this methodology to South Texas and have subsequently licensed over 750 square miles of 3-D seismic data. In late 2010, we initiated a project to reprocess, calibrate, merge and prestack time-migrate 700 square miles of 3-D seismic data over and near our AWP field. As these data are processed and merged with other available seismic data, and integrated with geologic data, we develop proprietary geo-science databases that we use to guide our exploration and development programs.

We use various recovery techniques, including gas lift, water flooding, pressure maintenance, and acid treatments to enhance crude oil and natural gas production. We also fracture reservoir rock through the injection of high-pressure fluid, the installation of gravel packs, and the insertion of coiled-tubing velocity strings to enhance and maintain production. The application of fracturing and coiled-tubing technology has resulted in significant increases in production and decreases in completion and operating costs, particularly in our South Texas Olmos and Eagle Ford operations. By December 31, 2010, we had successfully drilled and completed 30 horizontal multistage fracture completions in our South Texas area. We will continue to improve and employ this new technology in South Texas and apply this to other areas in which Swift Energy operates.

Swift Energy’s success at drilling both in South Texas and in Louisiana can be marked by requiring excellence in engineering. This is accomplished by elevating the quality of engineering first and operations second, with a focus on continuing improvement. A premium is placed on well planning. Drilling guidelines and design specifications are developed and implemented as best practices and standards, respectively, from which all planning and execution is derived. The emphasis on well planning has permeated throughout the organization and the results of that planning constantly show up in performance across all drilling operations. Lastly, the quality of the equipment and field personnel, together with a complete drilling process, is consistently enforced. This is the final mixture of resources that aids Swift Energy in moving toward becoming a top tier company.

6

Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2010 year-end proved reserves from continuing operations of 132.8 MMBoe and production of 8.3 MMBoe by area:

Core Area	Developed (MMBoe)	Undeveloped (MMBoe)	Total (MMBoe)	% of Reserves		% of Production		% Oil and NGLs	
South Texas - Olmos	28.0	21.4	49.4	37.2	%	33.5	%	39.5	%
South Texas – Eagle Ford	7.2	20.0	27.2	20.5	%	5.3	%	25.2	%
Total South Texas	35.2	41.4	76.6	57.7	%	38.8	%	42.3	%
Southeast Louisiana	11.3	9.8	21.2	15.9	%	44.5	%	84.6	%
Central Louisiana / E. Texas	8.1	12.7	20.9	15.7	%	8.9	%	63.8	%
South Louisiana	5.6	8.5	14.0	10.6	%	7.5	%	33.2	%
Other	0.2	0.0	0.1	0.1	%	0.3	%	0.6	%
Total	60.4	72.4	132.8	100	%	100	%	46.9	%

Focus Areas

Our operations are primarily focused in four core areas identified as Southeast Louisiana, South Texas, Central Louisiana/East Texas, and South Louisiana. In addition, we have a strategic growth area with acreage in the Four Corners area of southwest Colorado. South Texas is the oldest of our core areas, with our operations first established in the AWP field in 1989 and subsequently expanded with the acquisition of the Sun TSH and Las Tiendas fields during 2007. Operations in our Central Louisiana/East Texas area began in mid-1998 when we acquired the Masters Creek field in Louisiana and the Brookeland field in Texas, later adding the South Bearhead Creek field in Louisiana in late 2005. The Southeast Louisiana and South Louisiana areas were established when we acquired majority interests in producing properties in the Lake Washington field in early 2001, in the Bay de Chene and Cote Blanche Island fields in December 2004, and in the Bayou Sale, Bayou Penchant, Horseshoe Bayou, and Jeanerette fields in 2006.

South Texas

Eagle Ford. In 2010 the Company initiated an active exploration and development program in the Eagle Ford formation. During the year the Company drilled 22 wells in the Eagle Ford, including six non-operated joint venture wells. We completed 14 of the operated and three of the non-operated wells during the year. Four of the five wells awaiting completion at year-end have subsequently been completed. The Company owns a 50% working interest in the joint venture wells. These wells are operated by our partner during the drilling and completion phase. Swift Energy assumes operations when the wells are placed on production.

As of December 31, 2010, we owned drilling and production rights to 78,911 net acres overlaying the Eagle Ford, of which 73,764 are undeveloped. Based on the results of wells drilled in 2010 we have identified 56 proved undeveloped locations. During 2011 we plan to drill 25 wells targeting the Eagle Ford, including six wells to be drilled through our joint venture. Our December 31, 2010 proved reserves in this formation are 75% natural gas, 19% oil, and 6% natural gas liquids on a Boe basis.

Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled 10 horizontal wells and six vertical Olmos wells in 2010. These wells were all operated and 100% owned by Swift Energy. We completed eight of the horizontal wells during 2010 and one was completed shortly after year-end. One of the horizontal wells had a mechanical failure and was not completed. We completed five of six vertical wells during the year and one was abandoned. We also performed 16 fracture enhancements during the year. As of December 31, 2010 we owned drilling and production rights in 109,339 net acres overlying the Olmos (much of which also overlaps the Eagle Ford) in South Texas, of which 65,466 is undeveloped. At year-end we were operating 849 wells producing oil and natural gas from the Olmos sand formation at depths from 9,000 to 11,500 feet. Our South Texas reserves in this formation are approximately 61% natural gas, 32% natural gas liquids, and 7% oil on a Boe basis. At year-end 2010, we had 87 proved undeveloped locations in the Olmos. Our planned 2011 capital expenditures will include drilling up to 14 horizontal wells targeting the Olmos formation, and we plan to perform approximately 35 production enhancement projects including fracture stimulations, pumping unit installations and installation of additional compression.

Southeast Louisiana

Lake Washington. As of December 31, 2010, we owned drilling and production rights in 16,161 net acres in the Lake Washington field located in Southeast Louisiana nearshore waters within Plaquemines Parish. Since its discovery in the 1930's, the field has produced over 300 million Boe from multiple stacked Miocene sand layers radiating outward from a central salt dome and ranging in depth from 2,000 feet to 13,000 feet. The area around the dome is heavily faulted, thereby creating a large number of potential hydrocarbon traps. Approximately 93% of our proved reserves of 17.7 MMBoe in this field as of December 31, 2010, consisted of oil and NGLs. Oil and natural gas from approximately 103 currently producing wells is gathered to several platforms located in water depths from 2 to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2010 we drilled 14 development wells. We completed eight of the wells drilled during the year plus one well drilled in late 2009. Two wells were not completed due to mechanical failure, three were dry holes and one is still being evaluated. In our production optimization program we performed 20 recompletions, 29 sliding sleeve changes, 7 gas lift modifications, 1 acid job and 1 water shut-off. At year-end 2010, we had 65 proved undeveloped locations in this field. Our planned 2011 capital expenditures in the field will include drilling 4 to 5 wells and performing recompletions on at least 10 wells.

Bay de Chene. The Bay de Chene field is located along the border of Jefferson Parish and Lafourche Parish in nearshore waters approximately 25 miles from the Lake Washington field. As of December 31, 2010, we owned drilling and production rights in approximately 14,673 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. During 2010 we did not drill any wells in the Bay De Chene field. At year-end 2010, we had two proved undeveloped locations in the Bay de Chene field. During 2011, we plan to drill one to two wells in Bay de Chene.

Central Louisiana/East Texas

Burr Ferry. The Company has 32,724 net acres in the Burr Ferry field predominately located in Vernon Parish, Louisiana. Most of this acreage is within an area covered by a joint venture agreement with a large independent oil and gas producer. We entered into this joint venture agreement in 2009 for development and exploitation. In addition to holding a 50% working interest in the joint venture, the Company is also the fee mineral owner in most of this acreage. During 2010 the Company drilled and completed the first two non-operated wells in this joint venture. The reserves are approximately 65% oil and NGLs. We have identified 10 additional proved undeveloped locations in this field, and plan to drill up to four wells in this field in 2011.

Masters Creek. As of December 31, 2010, we owned drilling and production rights in 56,251 net acres and approximately 35,000 unleased fee mineral acres in the Masters Creek field. The Masters Creek field, located in Vernon Parish and Rapides Parish, Louisiana, consists of opposing dual lateral horizontal wells completed in the Austin Chalk formation. Oil and natural gas are produced from natural fractures encountered within the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 71% oil and NGLs. At year-end 2010, we had seven proved undeveloped locations. We deferred plans to drill a well in Masters Creek during 2010 and have tentatively rescheduled the well for drilling in the second half of 2011.

South Bearhead Creek. The South Bearhead Creek field is located in Beauregard Parish, Louisiana approximately 50 miles south of our Masters Creek field and 30 miles north of Lake Charles, Louisiana. The field was discovered in 1958 and is a large east-west trending anticline closure with cumulative production of over 4 million Boe. As of December 31, 2010, we owned drilling and production rights in 6,425 net acres in this field. Wells drilled in this field are completed in a multiple set of separate sands: Lower Wilcox - 12,500 to 14,500 feet; Middle and Upper Wilcox – 9,000 to 12,000 feet; and Cockfield – 8,000 to 9,000 feet. In 2010, we did not drill any wells in this field. At year-end

2010 we had 18 proved undeveloped locations in this field.

Brookeland. The Brookeland field area is located in Newton County and Jasper County, Texas, and Vernon Parish, Louisiana. As of December 31, 2010, we owned drilling and production rights in 69,540 net acres in this field. The field consists of opposing dual lateral horizontal wells completed in the Austin Chalk formation. Oil and natural gas are produced from natural fractures encountered within the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 57% oil and natural gas liquids. During 2010 we drilled and completed one operated and one non-operated well in this field. At the end of 2010 we had no proved undeveloped locations in the field.

South Louisiana

Cote Blanche Island. The Cote Blanche Island field is located in nearshore waters within St. Mary Parish. As of December 31, 2010, we owned drilling and production rights in 6,059 net acres in the Cote Blanche Island field. Similar to Lake Washington and Bay de Chene, it produces from Miocene sands surrounding a central salt dome. During 2010 we did not drill any wells in the Cote Blanche Island field, and at year-end 2010 we had three proved undeveloped locations in the field.

Bayou Sale, Horseshoe Bayou, Jeanerette, and Bayou Penchant. In October 2006 we acquired interests in four additional onshore fields in the area: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), and Bayou Penchant field in Terrebonne Parish. As of December 31, 2010, we owned drilling and production rights in a total of 18,637 net acres in these fields (5,700 in Bayou Sale, 5,138 in Horseshoe Bayou, 4,913 in Jeanerette, and 2,886 in Bayou Penchant). Bayou Sale and Horseshoe Bayou fields are adjacent to each other and located 13 miles southeast of our Cote Blanche Island field. They produce from several formations. The Jeanerette field is positioned on the flank of a large salt dome 12 miles north of Cote Blanche Island and produces form the Planulina sands. The Bayou Penchant field was discovered in the 1930s and is located approximately 44 miles southeast of Cote Blanche Island in Terrebonne Parish. Swift Energy holds an average 43% working interest in the wells in this non-operated field, which produces from a number of Middle Miocene sands.

In 2010, we did not drill any wells in our Bayou Sale, Horseshoe Bayou and Jeanerette fields. At year-end 2010, we had 24 proved undeveloped locations in the Bayou Sale, Horseshoe Bayou and Jeanerette fields.

Other

Four Corners. At the end of 2010, we had approximately 20,069 net acres leased in the Four Corners area of southwest Colorado.

New Zealand Areas (Discontinued Operations)

In December 2007, we agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of operations and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. In June 2008, we completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received nine months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit, with the first two payments received in February 2009 and February 2010, respectively. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending further development of this litigation.

In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the consolidated balance sheets.

Oil and Natural Gas Reserves

The following tables present information regarding proved reserves of oil and natural gas attributable to our interests in producing properties domestically as of December 31, 2010, 2009, and 2008. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us. Our Director of Reserves & Evaluations, the primary technical person responsible for overseeing the preparation of our reserves estimates, is a Licensed Professional Engineer, holds a bachelor's and a master's degree in chemical engineering, is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers, and has over 20 years of experience supervising or preparing reserves estimates. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, has audited 98% of our 2010 domestic proved reserves, 96% of our domestic proved reserves for 2009 and 97% of our domestic proved reserves for 2008. The audit by H.J. Gruy and Associates, Inc. conformed to the meaning of the term "reserves audit" as presented in Regulation S-K, Item 1202. The technical person at H.J. Gruy and Associates, Inc. primarily responsible for overseeing the audit, is a Licensed Professional Engineer, holds a degree in petroleum engineering, is past Chairman of the Gulf Coast Section of the Society of Petroleum Engineers, is past President of the Society of Petroleum Evaluation Engineers and has over 20 years experience overseeing reserves audits. Based on its audits, it is the judgment of H.J. Gruy and Associates, Inc. that Swift Energy used appropriate engineering, geologic, and evaluation principles and methods that are consistent with practices generally accepted in the petroleum industry.

The reserves estimation process involves reserves coordinators who are senior petroleum reservoir engineers whose duty is to prepare estimates of reserves, in accordance with the Commission's rules, regulations and guidelines, and who are part of multi-disciplinary teams responsible for each of the Company's major core asset areas. The multi-disciplinary teams consist of experienced reservoir engineers, geologists and other oil and gas professionals. Each reserves coordinator involved in the reserves estimation process has a minimum of 10 years reservoir engineering experience. The Director of Reserves and Evaluations supervises this process with multiple levels of review and reconciliation of reserves estimates to ensure they conform to SEC guidelines. Reserves data is also reported to and reviewed by senior management and the Board of Directors on a periodic basis. At year-end a reserves audit is performed by the third-party engineering firm, H.J. Gruy and Associates, Inc., to ensure the integrity and reasonableness of our reserves estimates. In addition, our independent Board members meet with H.J. Gruy and Associates, Inc. in executive session at least annually to review the annual audit report and the overall audit process

A reserves audit and a financial audit are separate activities with unique and different processes and results. These two activities should not be confused. As currently defined by the U.S. Securities and Exchange Commission within Regulation S-K, Item 1202, a reserves audit is the process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities. A financial audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

Estimates of future net revenues from our proved reserves and their PV-10 Value, for the years ended December 31, 2010 and 2009, are made based on either the preceding 12-months' average price based on closing prices on the first business day of each month, excluding the effects of hedging and are held constant, for that year's reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of natural gas contracts, the use of fixed and determinable contractual price escalations. For the year ended December 31, 2008, these same amounts are based on the same methodology except for the use of period-end oil and gas sales prices. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following tables.

The 12-month average 2010 prices for domestic operations were $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL compared to $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL at year-end 2009 and $4.96 per Mcf of natural gas, $44.09 per barrel of oil, and $25.39 per barrel of NGL at year-end 2008.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the SEC and their PV-10 Value as of December 31, 2010, 2009, and 2008. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. PV-10 is a non-GAAP measure; see the reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure, in the section below this table (MBoe amounts shown below are based on a natural gas conversion factor of 6 Mcf to 1 Boe):

	As of December 31,		
	2010	2009	2008
Estimated Proved Oil, NGL and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	190,454	155,405	172,214
Proved undeveloped	232,528	135,148	120,166
Total	422,982	290,553	292,380
Oil reserves (MBbl):			
Proved developed	16,782	19,659	22,710
Proved undeveloped	22,555	24,831	26,975
Total	39,337	44,490	49,685
NGL reserves (MBbl):			
Proved developed	11,874	11,237	10,701
Proved undeveloped	11,074	8,776	7,325
Total	22,948	20,012	18,026
Total Estimated Reserves (MBoe)	132,782	112,928	116,440
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 974	$ 766	$ 832
Proved undeveloped	803	557	481
PV-10 Value	$ 1,777	$ 1,323	$ 1,313

The PV-10 values for 2010, 2009, and 2008 are net of $82.3 million, $64.2 million, and $48.8 million of asset retirement obligation liabilities, respectively

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Future prices received for the sale of oil and natural gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and natural gas reserves.

The closest GAAP measure to PV-10, a non-GAAP measure, is the standardized measure of discounted future net cash flows. We believe PV-10 is a helpful measure in evaluating the value of our oil and natural gas reserves and many securities analysts and investors use PV-10. We use PV-10 in our ceiling test computations, and we also compare PV-10 against our debt balances. The following table provides a reconciliation between PV-10 and the standardized measure of discounted future net cash flows:

	As of December 31,		
	2010	2009	2008
(in millions)			
PV-10 Value	$ 1,777	$ 1,323	$ 1,313
Future income taxes (discounted at 10%)	(432)	(302)	(280)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,345	$ 1,021	$ 1,033

Domestic Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our domestic proved undeveloped reserves as of December 31, 2010:

Year Added	Volume (MMBoe)	% of PUD Volumes	PV-10 Value (in millions)	% of PUD PV-10 Value
2010	44.3	61 %	$ 358.1	45 %
2009	5.1	7 %	19.1	2 %
2008	4.5	6 %	86.8	11 %
2007	8.8	12 %	107.7	13 %
2006	4.8	7 %	107.8	13 %
2005	4.1	6 %	96.8	12 %
Prior to 2005	0.8	1 %	29.7	4 %
Total	72.4	100 %	$ 806.0	100 %

During 2010, we recorded 27.4 MMBoe of additional proved undeveloped reserves based on the results of the drilling program conducted during the year, primarily in the South Texas area. We also spent approximately $74.7 million in capital expenditures during the year to convert proved undeveloped reserves to proved developed reserves in the AWP and Lake Washington fields, resulting in the conversion of 5.4 MMBoe to proved developed reserves. As of December 31, 2010, approximately 1% of our total proved reserves consisted of undeveloped reserves added prior to 2005 in the Lake Washington field. The conversion of proved undeveloped reserves to proved developed reserves in recent years has been delayed by significant external factors, including the impacts of multiple hurricanes in key operating areas and restricted access to hydraulic fracturing services, rental equipment and related completion services in South Texas.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2010, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 132.8 MMBoe by approximately 0.2 MMBoe, and would increase the PV-10 Value of $1.8 billion by approximately $115 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.2 MMBoe and would decrease the PV-10 Value by approximately $116 million.

As of December 31, 2010 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.1 MMBoe and would increase the PV-10 Value by approximately $46 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.2 MMBoe and would decrease the PV-10 Value by approximately $46 million.

Oil and Gas Wells

The following table sets forth the total gross and net wells in which we owned an interest at the following dates:

	Oil Wells	Gas Wells	Total Wells(1)
December 31, 2010:			

Gross	485	846	1,331
Net	438.9	776.0	1,214.9
December 31, 2009:			
Gross	469	825	1,294
Net	406.6	758.9	1,165.5
December 31, 2008:			
Gross	510	817	1,327
Net	447.4	744.9	1,192.3

(1) Excludes 58 service wells in 2010, 59 service wells in 2009 and 65 service wells in 2008.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2010:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Alabama	8,120	1,580	176	1
Colorado	---	---	32,646	20,069
Louisiana (1)	126,771	108,222	73,233	47,186
Texas (2)	152,029	114,689	76,900	70,286
Wyoming	640	151	6,651	4,664
Offshore Louisiana	4,609	27	---	---
All other states	---	---	721	257
Total	292,169	224,669	190,327	142,463

(1) The Company holds the fee mineral (royalty) interest in a portion of the acreage located in Central Louisiana. The above table includes acreage where Swift is the fee mineral owner as well as a working interest owner. This acreage included in the above table totals 13,262 gross and 11,090 net developed acres and 41,871 gross and 25,341 net undeveloped acres. The Company also owns fee mineral interest in 35,057 net acres that is currently unleased and not included in the table above.

(2) In South Texas a substantial portion of our Eagle Ford and Olmos acreage overlaps. In most cases the Eagle Ford and Olmos rights are contracted under separate lease agreements. For the purposes of the above table, a surface acre where we have leased both the Eagle Ford and Olmos rights is counted as a single acre. In the Eagle Ford, we have 5,627 gross and 5,147 net developed acres and 90,172 gross and 73,764 net undeveloped acres. In the Olmos we have 45,280 gross and 44,873 net developed acres and 70,804 gross and 64,466 net undeveloped acres.

As of December 31, 2010, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 11% in Year 1, 27% in Year 2 and 37% in Year 3. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options.

Drilling and Other Exploratory and Development Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2010:

			Gross Wells			Net Wells	
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2010	Exploratory	11	10	1	9.5	8.5	1
	Development	45	38	7	41.9	34.9	7
2009	Exploratory	2	1	1	2	1	1
	Development	18	17	1	18	17	1
2008	Exploratory	3	2	1	1.8	1.5	0.3
	Development	123	108	15	120.0	106.0	14.0

Ten of the 11 exploratory wells were Eagle Ford appraisal test wells. The one exploratory dry well was an Olmos horizontal test well that encountered significant hydrocarbons but could not be completed due to mechanical failure.

Present Activities

As of December 31, 2010 we had 3 drilling rigs under contract working in South Texas and one in Lake Washington. Two non-operated wells were also being drilled at year-end, one in South Texas and one in Brookeland. Completion operations have been ongoing and all but one of the wells drilled before year-end have been subsequently completed. We have also continued the production optimization program in the Lake Washington field, involving gas lift enhancements and sliding sleeve shifts to change productive zones, to assist in mitigating natural field declines.

Operations

We generally seek to be the operator of the wells in which we have a significant economic interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors supervised by us provide this equipment and personnel. We employ drilling, production, and reservoir engineers, geologists, and other specialists who work to improve production rates, increase reserves, and lower the cost of operating our oil and natural gas properties.

Operations on our oil and natural gas properties are customarily administrated in accordance with COPAS guidelines. We charge a monthly per-well supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2010 totaled $12.5 million and ranged from $374 to $2,943 per well per month.

Fixed and Determinable Commitments

As of December 31, 2010 we had commitments to deliver fixed and determinable quantities of natural gas under term contracts as follows:

Year	Delivery Quantity (MMBTU)
2011	5,110,000
2012	7,670,000
2013	9,490,000
2014	10,590,000
2015	7,300,000

The sales price is tied to current spot gas prices at the time of delivery. Delivery quantities in excess of the minimums for any given year will proportionally reduce the minimum quantities for subsequent periods. The delivery point is in South Texas, and the Company’s proven reserves and production rates in the area significantly exceed the minimum obligations. There is no dedication of production from specific leases under the agreement.

Marketing of Production

We typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We usually sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. Shell Oil Company and its affiliates accounted for approximately 52 %, 48% and 28% of our gross oil and gas sales in 2010, 2009 and 2008, respectively. In 2008, Chevron Corporation and its domestic affiliates accounted for 25% of our gross oil and gas sales. No other purchasers accounted for more than 10% of our total oil and gas sales for the past three years. Due to the demand for oil and natural gas and the availability of other purchasers, we do not believe that the loss of any single oil or natural gas purchaser or contract would materially affect our revenues.

Our oil production from the Lake Washington field is either delivered into ExxonMobil’s crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices or at fixed prices tied to the then current NYMEX crude oil contract for the applicable month(s). Our natural gas production from this field is either consumed on the lease or is delivered into El Paso's Tennessee Gas Pipeline system and then sold in the spot market at prevailing prices. Natural gas delivered into Tennessee Gas Pipeline is processed at the Yscloskey plant. In 2008, we completed a connection which provides for the delivery of natural gas from this field to El Paso's Southern Natural Gas pipeline system (Sonat) and for the processing of natural gas delivered to Sonat at the Toca Plant.

In 2008, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP field with Enterprise Hydrocarbons L.P. and Enterprise South Texas Pipeline, replacing the ten-year agreements with Enterprise that expired in 2008. Processing revenues are received from Enterprise. The residue gas is sold at downstream connections with the Enterprise pipeline at prevailing market prices. Oil production is transported to market by truck or pipeline and sold at prevailing market prices.

In the Sun TSH and Fasken fields, our oil production is sold at prevailing market prices and transported to market by truck. Natural gas from the fields has historically been delivered either to Enterprise South Texas Gathering or Regency Gas Services. For natural gas delivered to Enterprise, the natural gas is sold to Enterprise; with Swift Energy receiving revenues from residue gas sales and processed liquids. For natural gas delivered to Regency, the natural gas production is transported to a downstream processing plant. We sell the residue gas at prevailing market prices and receive processing revenues from Regency. In the fourth quarter of 2010, Meritage Midstream Services, LLC completed construction of a new pipeline to the Fasken area. We entered into a gathering agreement providing for the transportation of our Eagle Ford production on the new pipeline from Fasken to Kinder Morgan Texas Pipeline, where it is sold at prices tied to monthly and daily natural gas price indices.

Our oil production from the Brookeland, Masters Creek and South Bearhead Creek fields is sold to various purchasers at prevailing market prices. Our natural gas production from the Brookeland and Masters Creek fields is processed under long term gas processing contracts with Eagle Rock Operating, LLC. The processed liquids and residue gas production are sold in the spot market at prevailing prices. South Bearhead Creek natural gas production is sold into the interstate market on Trunkline Gas Company's pipeline at prevailing market prices. There is field level extraction of a portion of the NGL's in the gas stream prior to delivery to Trunkline. Those NGL's are stored in a pressurized vessel and transported by truck to market for sale at prevailing market prices.

Our oil production from the Bay de Chene and Cote Blanche Island fields is transported on barges for sales to various purchasers at prevailing market prices. Natural gas production from both fields is sold into intrastate pipelines with prices tied to monthly and daily natural gas price indices.

In the fields of Bayou Sale, Horseshoe Bayou, High Island and Jeanerette in South Louisiana, we sell the oil production to various purchasers at prevailing market prices. The oil is transported to market by truck. Natural gas production for each of these fields is sold into one or more interstate pipelines at prevailing market prices.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and natural gas production from our continuing operations for the three-year period ended December 31, 2010:

	Year Ended December 31,		
	2010	2009	2008
Net Sales Volume:			
Oil (MBbls)	3,905	4,346	5,420
Natural Gas Liquids (MBbls)	1,138	1,183	1,211
Natural gas (MMcf) (1)	17,832	19,211	18,872
Total (MBoe)	8,015	8,731	9,777
Average Sales Price:			
Oil (Per Bbl)	$ 79.45	$ 60.07	$ 101.38
Natural Gas Liquids (Per Bbl)	$ 42.44	$ 31.36	$ 57.15
Natural gas (Per Mcf)	$ 4.38	$ 3.83	$ 9.28
Average Production Cost	$ 10.22	$ 8.79	$ 10.73

(Per Boe sold) (2)

(1) Excludes gas consumed in operations that is included in reported production volumes
(2)Excludes severance and ad valorem taxes

Oil and natural gas prices declined significantly in the latter part of 2008 from levels earlier in the year, and the average sales prices for 2008 are not indicative of prices in effect at the end of 2008. The prices above also do not include the effects of hedging. Quarterly prices and hedge adjusted pricing are detailed in the “Management’s Discussion and Analysis of Financial Condition and Results of Operations” section of this Form 10-K.

The following table provides a summary of our production, average sales prices, and average production costs for our AWP Olmos and Eagle Ford fields. These fields account for approximately 38% of the Company’s proved reserves based on total Boe as of December 31, 2010:

	Year Ended December 31,		
	2010	2009	2008
AWP Olmos & Eagle Ford			
Net Sales Volume:			
Oil (MBbls)	411	197	197
Natural Gas Liquids (MBbls)	624	496	344
Natural gas (MMcf) (1)	8,358	5,623	5,125
Total (MBoe)	2,428	1,630	1,395
Average Sales Price:			
Oil (Per Bbl)	$ 76.91	$ 58.52	$ 95.81
Natural Gas Liquids (Per Bbl)	$ 40.38	$ 29.68	$ 50.94
Natural gas (Per Mcf)	$ 4.36	$ 3.63	$ 9.15
Average Production Cost (Per Boe sold) (2)	$ 6.88	$ 6.51	$ 9.35

(1) Excludes gas consumed in operations that is included in reported production volumes
(2) Excludes severance and ad valorem taxes

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or individual injuries. The oil and natural gas exploration business is also subject to environmental hazards, such as oil spills, natural gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. See "1A. Risk Factors" of this report for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance, operators extra expense insurance, and property damage insurance. Our standing Insurable Risk Advisor Team, which includes individuals from operations, drilling, facilities, reserves, legal, HSE and finance meets regularly to evaluate risks, review property values, review and monitor claims, review market conditions and assist with the selection of coverages. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us. See Item 1A – Risk Factors.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and participating collars when appropriate. At December 31, 2010, we had natural gas price floors in effect that covered a portion of our natural gas production for January to April 2011. These floors cover production of 4,250,000 MMBtu from January through April 2011 with strike prices ranging between $3.77 and $4.30 per MMBtu.

Competition

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and natural gas properties, as well as for equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and natural gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. Our ability to replace and expand our reserves base depends on our continued ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling and acquisition.

Federal Leases

Some of our properties are located on federal oil and natural gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and administrative orders affect the terms of leases, and in turn may affect our exploration and development plans, methods of operation, and related matters.

Litigation

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In our opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations. We have further discussed our New Zealand litigation in footnote 8 of the notes to consolidated financial statements ("Discontinued Operations").

Employees

At December 31, 2010, we employed 292 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2010, we occupied approximately 202,355 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten-year lease expiring February 2015. The lease requires payments of approximately $450,000 per month. We also have field offices in various locations from which our employees supervise local oil and natural gas operations.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, changes in and stock ownership of our directors and executive officers, together with other documents filed with the Securities and Exchange Commission under the Securities Exchange Act can be accessed free of charge on our web site at www.swiftenergy.com as soon as reasonably practicable after we electronically file these reports with the SEC. All exhibits and supplemental schedules to these reports are available free of charge through the SEC web site at www.sec.gov. In addition, we have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. We have posted this Code of Ethics on our website, where we also intend to post any waivers from or amendments to this Code of Ethics.

Item 1A. Risk Factors

The nature of the business activities conducted by Swift Energy subjects it to certain hazards and risks. The following is a summary of all the material risks relating to our business activities.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices
would adversely affect our financial results.

Our future revenues, net income, cash flow, and the value of our oil and natural gas properties depend primarily upon market prices for oil and natural gas. Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. The recent oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, currency exchange rates, and political conditions in major oil producing regions, especially the Middle East. A significant decrease in price levels for an extended period would negatively affect us in several ways:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to increase production or replace reserves;
- certain reserves would no longer be economic to produce, leading to both lower cash flow and proved reserves;
- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserves values, reducing our liquidity and possibly requiring mandatory loan repayments; and
- access to other sources of capital, such as equity or long term debt markets, could be severely limited or unavailable in a low price environment.

Consequently, our revenues and profitability would suffer.

Enactment of Congressional and regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been proposed or are under consideration by the Obama administration, Congress and various federal agencies. Among these proposals are: (1) climate change legislation introduced in Congress, Environmental Protection Agency regulations, carbon emission "cap-and-trade" regimens, and related proposals, none of which have been have been adopted in final form; (2) proposals contained in the President's budget, along with legislation introduced in Congress, none of which have been enacted by both houses of Congress, to repeal various tax deductions or exemptions available to oil and gas producers, such as the tax deduction for intangible drilling and development costs, which if eliminated could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; and (3)legislation being considered by Congress that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, which could affect Company operations, their effectiveness, and the costs thereof. Any such future laws and regulations could result in increased costs or additional operating restrictions, and could have an effect on demand for oil and gas or prices at which it can be sold. Until any such legislation or regulations are enacted or adopted, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

Estimates of proved reserves are uncertain, and revenues from production may vary significantly from expectations.

The quantities and values of our proved reserves included in this report are only estimates and subject to numerous uncertainties. Estimates by other engineers might differ materially. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation. These estimates depend on assumptions regarding quantities and production rates of recoverable oil and natural gas reserves, future prices for oil and natural gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant.

Any significant variance from the assumptions used could result in the actual amounts of oil and natural gas ultimately recovered and future net cash flows being materially different from the estimates in our reserves reports. In addition, results of drilling, testing, production, and changes in prices after the date of the estimates of our reserves may result in substantial downward revisions. These estimates may not accurately predict the present value of net cash flows from our oil and natural gas reserves.

At December 31, 2010, approximately 55% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

Our South Louisiana and Southeast Louisiana core areas remain subject to damage from hurricane activity in the Gulf of Mexico, which could cause a pipeline outage or cause us to suffer significant losses.

Approximately 27% of our 2010 reserves and 52% of our 2010 production are located in our South Louisiana and Southeast Louisiana core areas. Hurricane activity in 2007 and 2008 resulted in production curtailments and physical damage to our Gulf Coast operations. For example, a significant percentage of our production was shut down by Hurricanes Katrina and Rita in 2005, and by Hurricanes Gustav and Ike in 2008. Due to increased costs after the 2005 hurricanes, we no longer carry business interruption insurance. If hurricanes damage the Gulf Coast region where we have a significant percentage of our operations, our cash flow would suffer. This decrease in cash flow, depending on the extent of the decrease, could reduce the funds we would have available for capital expenditures and reduce our ability to borrow money or raise additional capital.

The continuing pressure on the global credit and financial markets could materially and adversely impact our financial results.

As extensively reported, global credit and financial markets experienced extreme disruptions beginning in the second half of 2008, severely diminishing liquidity and credit availability, volatility in consumer confidence, declines in economic growth, increases in unemployment rates, and uncertainty about economic stability. We cannot assure you that there will not be further deterioration in credit, financial, or commodities markets. These economic conditions have led to higher volatility for crude oil and natural gas prices, as demonstrated by the decline in commodity prices which occurred during the later part of 2008 and into 2009. Our profitability will be significantly affected by decreased demand and lower commodity prices. Our future access to capital and the availability of future financing could be limited due to tightening credit markets that could affect our ability to fund our capital projects.

Our operating results may be adversely affected if economic conditions impact the financial viability of our insurers, oil and gas purchasers, suppliers and commodity derivatives counterparties.

Global economic conditions may adversely affect the financial viability of and increase the credit risk associated with our purchasers, suppliers, insurers, and commodity derivative counterparties to perform under the terms of contracts or financial arrangements we have with them. Although we have heightened our level of scrutiny of our contractual counterparties, our assessment of the risk of non-performance by various parties is subject to sudden swings in the financial and credit markets. This same crisis may adversely impact insurers and their ability to pay current and future insurance claims that we may have.

Negative credit market conditions may adversely affect our access to capital, our liquidity and ability to refinance our debt.

Our future access to capital could be limited due to tightening credit markets that could affect our ability to fund our future capital projects. Negative credit market conditions could materially affect our liquidity and may inhibit our lenders from fully funding our line of credit or cause them to make the terms of our line of credit costlier or more restrictive. We are subject to semi-annual reviews of our borrowing base and commitment amount under our line of credit, and do not know the result of future redeterminations or the effect of then current oil and gas prices on that process. Additionally, our line of credit matures in October 2015, and although it has a zero balance as of December 31, 2010, long-term restriction or freezing of the capital markets may affect the availability or pricing of our renewal of the line of credit.

We have previously incurred a write-down of the carrying values of our properties and could incur additional write-downs in the future.

The SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and natural gas properties for possible write-down or impairment. Starting with our financial statements ending December 31, 2009 the unescalated prices are calculated under the rules using a twelve month rolling average price from the first business day of each month. Any capital costs in excess of the ceiling must be permanently written down. Low oil and gas prices at December 31, 2008 and March 31, 2009 led to $473.1 and $50.0 million non-cash after-tax write-downs of our oil and gas properties, respectively. If oil and gas prices decline in the future, to the degree such that we incur additional capital costs on oil and gas properties and add proved reserves, we may be required to record further write-downs of our oil and gas properties in subsequent periods.

Our oil and natural gas exploration and production business involves high risks and we may suffer uninsured losses.

These risks include blowouts, explosions, adverse weather effects and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, such as business interruption, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Our level of debt could reduce our financial flexibility.

As of December 31, 2010, our total debt comprised approximately 35% of our total capitalization. Although our bank credit facility and indentures limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness, we will be permitted to incur significant additional indebtedness, including secured indebtedness, in the future if specified conditions are satisfied. Higher levels of indebtedness could negatively affect us by requiring us to dedicate a substantial portion of our cash flow to the payment of interest, and limiting our ability to obtain financing or raise equity capital in the future.

If we cannot replace our reserves, our revenues and financial condition will suffer.

Unless we successfully replace our reserves, our long-term production will decline, which could result in lower revenues and cash flow. When oil and natural gas prices decrease, our cash flow decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank credit facility. Even if we have the capital to drill, unsuccessful wells can hurt our efforts to replace reserves. Additionally, lower oil and natural gas prices can have the effect of lowering our reserves estimates and the number of economically viable prospects that we have to drill.

Drilling wells is speculative and capital intensive.

Developing and exploring properties for oil and natural gas requires significant capital expenditures and involves a high degree of financial risk, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The budgeted costs of drilling, completing, and operating wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an oil or natural gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- Hurricanes, tropical storms or other natural disasters;
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contaminate
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented, as is the case in our declining business interruption insurance following the hurricanes in 2005. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our financial condition.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Reserves on acquired properties may not meet our expectations, and we may be unable to identify liabilities associated with acquired properties or obtain protection from sellers against associated liabilities.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property's production and profitability. In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and natural gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Louisiana and Texas, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

In addition, our assessment of acquired properties may not reveal all existing or potential problems or liabilities, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the properties may not perform in accordance with our expectations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities, if at all, to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects. In addition, a variety of factors, including geological and market-related, can cause a well to become uneconomical or only marginally economical. For example, if oil and natural gas prices are much lower after we complete a well than when we identified it as a prospect, the completed well may not yield commercially viable quantities.

In many instances, title opinions on our oil and gas acreage are not obtained if in our judgment it would be uneconomical or impractical to do so.

As is customary in the industry, we generally acquire oil and natural gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and expose us to risk of financial loss.

We enter into hedging transactions for our oil and natural gas production to reduce exposure to fluctuations in the price of oil and natural gas, primarily to protect against declines in prices, although we typically enter into only short-term hedges covering less than 50% of our anticipated production, which limits the price protection they provide. Our hedges at year-end 2010 consisted of natural gas price floors with strike prices ranging between \$3.77 and \$4.30. Our hedging transactions have also historically consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors. We intend to continue to enter into these types of hedging transactions in the foreseeable future when appropriate. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions other than floors may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Additionally, hedging transactions other than floors may expose us to cash margin requirements.

We may have difficulty competing for oil and gas properties, equipment, supplies, oilfield services, and trained and experienced personnel.

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and natural gas properties, as well as for the equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and natural gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. As demand increases for equipment, services, and personnel, we may experience increased costs and various shortages and may not be able to obtain the necessary oilfield services and trained personnel.

Our business depends on oil and natural gas transportation facilities, some of which are owned by others.

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Governmental laws and regulations are costly and stringent, especially those relating to environmental protection.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in our efforts to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operations. Changes in or additions to environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could have a material adverse effect on our operations and financial position.

Climate change legislation and regulatory initiatives could result in increased compliance costs and reduced demand for the oil and natural gas we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” or “GHGs,” and including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere and other climatic changes. In December 2009, the EPA issued an “endangerment and cause or contribute finding” for greenhouse gases under section 202(a) of the Clean Air Act, which will allow the EPA to adopt rules under the CAA that directly regulate greenhouse gases. Accordingly, the EPA has adopted regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in

2011 for emissions occurring in 2010 and, most recently, on November 8, 2010, adopted amendments to this rule expanding the existing greenhouse gas monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmissions, storage and distribution facilities, beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, primarily through means of a cap and trade program that would require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. More than one-third of the states (but not currently including Louisiana or Texas) either individually or through multi-state initiatives already have begun implementing legal measures to reduce or report upon emissions of greenhouse gases. Any adoption of legislation or new regulations imposing reporting obligations upon, or limiting emissions of greenhouse gases from, our equipment and operations could adversely impact our business, result in increased compliance costs or additional operating restrictions, and have an adverse effect on demand for the oil and natural gas we produce.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Legislation introduced in Congress last year called the "Fracturing Responsibility and Awareness of Chemicals Act," or "FRAC Act," would repeal an exemption in the federal Safe Drinking Water Act ("SWDA") for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. If enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The FRAC Act also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available and make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. The EPA also has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, disclosure of chemicals used in the fracturing process, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of the FRAC Act or any other federal or state laws or regulations imposing disclosure obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas wells in shale formations, increase our costs of compliance, cause delays in permitting, and adversely affect our business.

Recent attention to the use of diesel fuel in hydraulic fracturing could intensify EPA regulation under the Safe Drinking Water Act.

The Safe Drinking Water Act, as amended, currently excludes hydraulic fracturing from EPA regulation so long as no diesel fuel is used in the fracturing process. Recent Congressional investigations have shown that despite the absence of permits being issued for diesel fuel use in fracturing, a number of companies have acknowledged incorporating diesel fuel into their fracturing fluids. Should the EPA decide that companies using diesel fuel in fracturing operations are in violation of the Safe Drinking Water Act, penalties could be imposed on those companies, possibly retroactive in nature. Enhanced EPA regulation of fracturing could impose additional costs on the operations of the Company, alter the effectiveness of fracturing as currently conducted, and alter development plans using the fracturing process. The vendors which the Company contracts with do not currently use diesel fuel in their fracturing fluids.

Environmental Regulations

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, and other ecologically sensitive and protected areas, and impose substantial remedial liabilities for pollution resulting from drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of significant investigatory or remedial obligations, and the imposition of injunctive relief that limits or prohibits our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current environmental laws and regulations and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

We currently own or lease, and have in the past owned or leased, numerous properties in connection with our operations that have been used for the exploration and production of oil and natural gas for many years. Although we have used operation and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as “CERCLA” or the “Superfund” law, the federal Resource Conservation and Recovery Act or “RCRA,” the federal Clean Water Act, the federal Clean Air Act, the federal Oil Pollution Act or “OPA,” and analogous state laws. Under such laws and any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment.

Our operations in Louisiana state waters are subject to OPA, which imposes a variety of requirements related to the prevention of oil spills, and liability for damages resulting from such spills in United States waters. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for water based facilities in Louisiana require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party fails to report the spill or cooperate fully in any resulting cleanup. The OPA also requires a responsible party to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe our operations are in substantial compliance with OPA requirements.

United States Federal and State Regulation of Oil and Natural Gas

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the federal government and are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The Federal Energy Regulatory Commission ("FERC") is continually proposing and implementing new rules and regulations affecting the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. Some recent FERC proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines.

Our sales of crude oil, condensate and NGLs are not currently subject to FERC regulation. However, the ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation.

Since December 2007, Congress has passed the Energy Independence and Security Act of 2007, the Energy Economic Stabilization Act of 2008, and the American Recovery and Reinvestment Act of 2009, each of which contains various provisions affecting the oil and gas industry and related tax provisions. In future periods, Congress may decide to revisit legislation introduced in prior sessions to repeal existing incentives or impose new taxes on the exploration and production of oil and natural gas, and/or create new incentives for alternative energy sources. If enacted, such legislation could reduce the demand for and uses of oil, natural gas and other minerals and/or increase the costs incurred by the Company in its exploration and production activities, which could affect the Company's revenues, costs, and profits.

Production of any oil and natural gas by us will be affected to some degree by state regulations. Many states in which we operate have statutory provisions regulating the production and sale of oil and natural gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and natural gas and to protect correlative rights to produce oil and natural gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and natural gas produced by assigning allowable rates of production to each well or proration unit, which could restrict the rate of production below the rate that a well would otherwise produce in the absence of such regulation. In addition, certain state regulatory authorities can limit the number of wells or the locations where wells may be drilled. Any of these actions could negatively affect the amount or timing of revenues.

Item 1B. Unresolved Staff Comments

None.

24

Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

ASC — Accounting Standards Codification.
Bbl — Barrel or barrels of oil.
Bcf — Billion cubic feet of natural gas.
Bcfe — Billion cubic feet of natural gas equivalent (see Mcfe).
Boe — Barrels of oil equivalent.

Condensate — Liquid hydrocarbons that are found in natural gas wells and condense when brought to the well surface. Condensate is used synonymously with oil.

Developed Oil and Gas Reserves — Oil and natural gas reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods. 1

Development Well — A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Discovery Cost — With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred exploration and development costs (exclusive of future development costs) by net reserves added during the period through extensions, discoveries, and other additions.

Dry Well — An exploratory or development well that is not a producing well.

EBITDA — Earnings before interest, taxes, depreciation, depletion and amortization.

EBITDAX — Earnings before interest, taxes, depreciation, depletion and amortization, and exploration expenses. Since Swift Energy uses full-cost accounting for oil and property expenditures, as noted in footnote one of the accompanying consolidated financial statements, exploration expenses are not applicable to Swift Energy.

Exploratory Well — 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 natural gas in another reservoir. 2

FASB — The Financial Accounting Standards Board.

Gross Acre — An acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

Gross Well — A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

MBbl — Thousand barrels of oil.
MBoe — Thousand barrels of oil equivalent.
Mcf — Thousand cubic feet of natural gas.

Mcfe — Thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate, or natural gas liquids to 6 Mcf of natural gas.

MMBbl — Million barrels of oil.
MMBoe — Million barrels of oil equivalent.

MMBtu — Million British thermal units, which is a heating equivalent measure for natural gas and is an alternate measure of natural gas reserves, as opposed to Mcf, which is strictly a measure of natural gas volumes. Typically, prices quoted for natural gas are designated as price per MMBtu, the same basis on which natural gas is contracted for sale.

MMcf — Million cubic feet of natural gas.
MMcfe — Million cubic feet of natural gas equivalent (see Mcfe).

Net Acre — A net acre is deemed to exist when the sum of fractional working interests owned in gross acres equals one. The number of net acres is the sum of fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Net Well — A net well is deemed to exist when the sum of fractional working interests owned in gross wells equals one. The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

NGL — Natural gas liquid.

Producing Well — An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Proved Oil and Gas Reserves — 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. For reserves calculations on or after December 31, 2009, economic conditions include prices based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. 3

Proved Undeveloped (PUD) Locations — A location containing proved undeveloped reserves.

PV-10 Value — The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization. PV-10 Value is a non-GAAP measure and its use is explained under "Item 2. Properties - Oil and Natural Gas Reserves" above in this Form 10-K.

Undeveloped Oil and Gas Reserves — Oil and natural gas 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. 4

Notes to Abbreviations and Terms Above

The Regulation S-X definitions below refer to the revised definitions effective January 1, 2010.

1. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(6) of Regulation S-X.
2. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(13) of Regulation S-X.
3. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(22) of Regulation S-X.
4. This is only an abbreviated definition. Please refer to Securities and Exchange Commission's definition of this term at Rule 4-10(a)(31) of Regulation S-X.

Item 3. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation and claims incidental to our business. We have further discussed our New Zealand litigation in footnote 8 of the notes to consolidated financial statements ("Discontinued Operations")

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

No matters were submitted during the fourth quarter of 2010 to a vote of security holders.

PART II

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

Common Stock, 2009 and 2010

Our common stock is traded on the New York Stock Exchange under the symbol “SFY.” The high and low quarterly closing sales prices for the common stock for 2009 and 2010 were as follows:

	2009				2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$4.95	$7.46	$13.09	$20.88	$24.52	$26.17	$24.94	$27.99
High	$21.23	$19.38	$25.61	$25.43	$33.55	$38.17	$29.55	$40.83

Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our credit agreements, as discussed in Note 4 to the consolidated financial statements, and we presently intend to continue a policy of using retained earnings for expansion of our business.

We had approximately 183 stockholders of record as of December 31, 2010.

Stock Repurchase Table

The following table summarizes repurchases of our common stock occurring during the fourth quarter of 2010:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
10/01/10 – 10/31/10 (1)	529	$ 32.14	---	$ ---
11/01/10 – 11/30/10 (1)	983	$ 33.25	---	---
12/01/10 – 12/31/10 (1)	77	$ 40.15	---	---
Total	1,589	$ 33.21	---	$ ---

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

Equity Compensation Plan Information

The table summarizing information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2010 is located in Note 6 of Notes to Consolidated Financial Statements.

Share Performance Graph

The following Share Performance Graph shall not be deemed to be “soliciting material” or to be “filed” with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 6. Selected Financial Data

(in thousands except per share and well amounts)	2010	2009	2008	2007	2006
Total Revenues from Continuing Operations (1)	$ 438,429	$ 370,445	$ 820,815	$ 654,121	$ 550,836
Income (Loss) from Continuing Operations, Before Income Taxes and Change in Accounting Principle (1)	$74,308	$ (64,617)	$ (412,758)	$ 244,556	$ 248,308
Income (Loss) from Continuing Operations (1)	$46,475	$ (39,076)	$ (257,130)	$ 152,588	$ 151,074
Net Cash Provided by Operating Activities - Continuing Operations	$ 258,996	$ 226,176	$ 582,027	$ 442,282	$ 383,241
Per Share and Share Data					
Weighted Average Shares Outstanding(1)	38,300	33,594	30,661	29,984	29,265
Earnings per Share--Basic(1)	$1.19	$ (1.16)	$ (8.39)	$ 5.09	$ 5.16
Earnings per Share--Diluted(1)	$1.18	$ (1.16)	$ (8.39)	$ 4.98	$ 5.03
Shares Outstanding at Year-End	41,999	37,457	30,869	30,179	29,743
Book Value per Share at Year-End	$ 20.95	$ 18.12	$ 19.47	$ 27.70	$ 26.83
Market Price					
High	$ 40.83	$ 25.61	$ 67.03	$ 47.72	$ 51.84
Low	$ 24.52	$ 4.95	$ 15.30	$ 35.98	$ 35.48
Year-End Close	$ 39.15	$ 23.96	$ 16.81	$ 44.03	$ 44.81
Assets					
Current Assets	$ 160,817	$ 108,600	$ 78,086	$ 199,950	$ 83,783
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$ 1,572,845	$ 1,315,964	$ 1,431,447	$ 1,760,195	$ 1,239,722
Total Assets	$ 1,746,375	$ 1,434,765	$ 1,517,288	$ 1,969,051	$ 1,585,682
Liabilities					
Current Liabilities	$ 162,787	$ 103,604	$ 153,499	$ 210,161	$ 145,471
Long-Term Debt	$ 471,624	$ 471,397	$ 580,700	$ 587,000	$ 381,400
Total Liabilities	$ 866,358	$ 755,866	$ 916,411	$ 1,132,997	$ 787,765
Stockholders' Equity	$ 880,017	$ 678,899	$ 600,877	$ 836,054	$ 797,917

Number of Domestic Employees	292	295	334	298	272
Domestic Producing Wells					
Swift Operated	1,212	1,146	1,168	1,091	926
Outside Operated	119	148	159	127	112
Total Domestic Producing Wells	1,331	1,294	1,327	1,218	1,038
Domestic Wells Drilled (Gross)	56	20	126	69	55
Domestic Proved Reserves					
Natural Gas (Bcf)	423.0	290.6	292.4	343.8	269.7
Oil Reserves (MBoe)	39.3	44.5	49.7	58.3	62.0
NGL Reserves (MBoe)	23.0	20.0	18.0	18.2	11.5
Total Domestic Proved Reserves (MMBoe equivalent)	132.8	112.9	116.4	133.8	118.4
Domestic Production (MMBoe equivalent)	8.3	9.1	10.0	10.6	9.4
Domestic Average Sales Price (2)					
Natural Gas (per Mcf produced)	$ 3.96	$ 3.48	$ 8.54	$ 6.42	$ 6.44
Natural Gas Liquids (per barrel)	$ 42.44	$ 31.36	$ 57.15	$ 49.72	$ 38.70
Oil (per barrel)	$ 79.45	$ 60.07	$ 101.38	$ 71.92	$ 64.28
Boe Equivalent	$ 52.42	$ 41.05	$ 79.00	$ 61.49	$ 56.89

(1) Amounts have been retroactively adjusted in all periods presented to give recognition to: (a) discontinued operations related to the sale of our New Zealand oil & gas assets, and (b) the conversion of production and reserves volumes to a Boe basis.

(2) These prices do not include the effects of our hedging activities which were recorded in "Price-risk management and other, net" on the accompanying statements of operations. The hedge adjusted prices are detailed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this Form 10-K. Natural gas sales prices represents the amount realized per MCF of production.

Item 7. Management's Discussion and Analysis of
Financial Condition and Results of Operations

You should read the following discussion and analysis in conjunction with our financial information and our audited consolidated financial statements and accompanying notes for the years ended December 31, 2009, 2008, and 2007 included with this report. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand discontinued operations. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 39 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for liquids-rich Eagle Ford shale and Olmos tight sands development. Oil production accounted for 47% of our 2010 production and 71% of our oil and gas revenues, and combined production for both oil and natural gas liquids ("NGLs") made up 61% of our 2010 production and 82% of our oil and gas sales. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during 2010.

2010 Highlights

Increases in Earnings and Cash Flow. Our year-to-year income from continuing operations increased by $85.6 million and cash provided by operating activities increased by $32.8 million, as oil and NGL prices received in 2010 were 32% and 35% higher, respectively, than the average prices we received in 2009, while natural gas prices increased 14% in 2010.

Improved Liquidity at Year-End 2010. In November 2010, we raised $140.1 million net through an underwritten public stock offering of 4.0 million shares of our common stock at a price of $36.60 per share. This followed an equity offering in the third quarter of 2009 when we raised $108.8 million net in the sale of 6.21 million shares of our common stock at a price of $18.50 per share. Taken together with $300.0 million of borrowing capacity under our credit agreement at December 31, 2010, our improved liquidity provides capital, if needed, for our expanded 2011 drilling program.

Increased Reserves. Year-end 2010 total proved reserves increased 18%, or 19.9 MMBoe over reserves quantities at December 31, 2009, with a year-end 2010 PV-10 value increasing by approximately $450 million to $1.8 billion.

South Texas Drilling. During 2010 we drilled 32 horizontal wells and an additional 6 vertical wells helping us evaluate Eagle Ford and Olmos acreage positions in our South Texas area. At year-end, our South Texas core area surpassed Southeast Louisiana in terms of both production and proven reserves. We also entered into long-term agreement with a major industry service provider for South Texas, securing access to fracing services at competitive prices for a two-year period.

Shareholder Return. We had annual shareholder return during 2010 of 63%.

Development Joint Ventures. Over the last 15 months we have entered into joint venture agreements with large independent oil and gas producers covering acreage in both our AWP and Burr Ferry fields, allowing us to both monetize a portion of our significant acreage positions (including a 26,000 acre portion of our Eagle Ford Shale acreage in McMullen County, Texas) and share costs of development drilling in these fields in order to accelerate their development.

2011 Objectives

In 2011, we are focused on accelerating our pace of development in South Texas, improving our results through more efficient execution and exploiting other areas of our asset base. Our exposure to liquids rich production growth in South Texas, our oil production in South Louisiana, our growing leasehold acreage in the Austin Chalk and our deep exploration prospect inventory along the Gulf Coast together provide a uniquely positioned resource portfolio for investors to evaluate. For 2011, we are targeting an increase in production volumes of 25% to 30% over 2010 levels and reserves growth of 15% to 20% over 2010 levels. The Company has also begun to explore entering into select joint venture arrangements to help accelerate the drilling and development of particular fields.

Results of Operations

Summary Prior Year Comparison

In 2010 we had revenues of $438.4 million, an increase of 18% compared to 2009 levels. Our weighted average sales price received increased 28% to $52.42 per Boe for 2010 from $41.05 per Boe in 2009. This $68.0 million increase in revenues from 2009 levels was due to higher oil, natural gas, and NGL prices during 2010, offset somewhat by an 8% decrease in production mainly due to natural declines in our Southeast Louisiana fields.

Our overall costs and expenses decreased in 2010 by $70.9 million when compared to 2009 levels, but were higher on a Boe basis, as the 2009 period included a non-cash write-down of our oil and gas properties of $79.3 million in the first quarter. Depreciation, depletion and amortization expense decreased 2%, mainly due to higher reserves volumes and lower production when compared to the 2009 period, partially offset by a higher depletable property base in the 2010 period. Lease operating costs increased by 7% due to higher workover costs, natural gas processing costs, and saltwater disposal costs. Severance and other taxes increased 11% mainly due to increased oil and gas revenues.

Our net income for 2010 was $46.3 million, while our net loss in 2009 was $39.3 million.

Revenues

2010. Our revenues in 2010 increased by 18% compared to revenues in 2009 due to higher oil and gas prices after taking into account decreased production. Average oil prices that we received were 32% higher than those received during 2009, while natural gas prices were 14% higher, and NGL prices were 35% higher.

2009. Our revenues in 2009 decreased by 55% compared to revenues in 2008 primarily due to lower oil and gas prices, as oil, natural gas, and NGL prices we received in 2009 were 41%, 59%, and 45% lower, respectively, than the average prices we received a year earlier.

2008. Our 2008 production was adversely affected by Hurricanes Gustav and Ike. As a result of these hurricanes, approximately 0.8 MMBoe of production was shut-in during 2008 predominantly in Southeast Louisiana. All of this shut-in production was brought online in 2009.

Crude oil production was 47% of our production volumes in 2010, 48% in 2009, and 54% in 2008. Natural gas production was 39% of our production volumes in 2010, 39% in 2009, and 34% in 2008. The remaining production in each year was from natural gas liquids (NGLs).

Our properties are divided into the following four core areas, each of which includes the fields listed:

- South Texas

- Olmos

AWP
Sun TSH
Las Tiendas

- Eagle Ford

Hawkville AWP
Hawkville Artesia Wells
Hawkville Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central Louisiana/East Texas

Brookeland
South Bearhead Creek
Masters Creek
Burr Ferry

- South Louisiana

Horseshoe Bayou/Bayou Sale
Jeanerette
Cote Blanche Island

The following table provides information regarding the changes in the sources of our oil and gas production and volumes for the years ended December 31, 2010, 2009, and 2008:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2010	2009	2008	2010	2009	2008
S. E. Louisiana	$246.2	$232.5	$486.4	3,706	4,782	5,323
South Texas	120.4	77.4	158.6	3,235	2,721	2,793
Central Louisiana / E. Texas	40.4	37.0	84.7	738	864	1,034
South Louisiana	29.0	24.1	61.6	628	660	850
Other	0.6	0.7	2.6	23	28	49
Total	$436.6	$371.7	$793.9	8,330	9,055	10,049

2010 Revenues Breakdown. Oil and gas sales in 2010 increased by 17%, or $64.9 million, from the level of those revenues for 2009, and our net production volumes in 2010 decreased by 8%, or 0.7 MMBoe, over net production volumes in 2009. Average prices for oil increased to $79.45 per Bbl in 2010 from $60.07 per Bbl in 2009. Average natural gas prices increased to $3.96 per Mcf in 2010 from $3.48 per Mcf in 2009. Average NGL prices increased to $42.44 per Bbl in 2010 from $31.36 per Bbl in 2009.

In 2010, our $64.9 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $97.8 million favorable impact on sales, of which $75.7 million was attributable to the 32% increase in average oil prices received, $12.6 million was attributable to the 35% increase in NGL prices, and $9.5 million was attributable to the 14% increase in average natural gas prices received; and
- Volume variances that had a $32.9 million unfavorable impact on sales, with $26.5 million of decreases attributable to the 0.4 million Bbl decrease in oil production volumes, $1.4 million of decreases attributable to the less than 0.1 million Bbl decrease in NGL production volumes and $5.0 million of decreases attributable to the 1.4 Bcf decrease in natural gas production volumes.

2009 Revenues Breakdown. Oil and gas sales in 2009 decreased by 53%, or $422.1 million, from the level of those revenues for 2008, and our net production volumes in 2009 decreased by 10%, or 1.0 MMBoe, compared to net production volumes in 2008. Average prices for oil decreased to $60.07 per Bbl in 2009 from $101.38 per Bbl in 2008. Average natural gas prices decreased to $3.48 per Mcf in 2009 from $8.54 per Mcf in 2008. Average NGL prices decreased to $31.36 per Bbl in 2009 from $57.15 per Bbl in 2008.

In 2009, our $422.1 million decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $317.2 million unfavorable impact on sales, of which $179.5 million was attributable to the 41% decrease in average oil prices received, $30.5 million was attributable to the 45% decrease in average NGL prices, and $107.2 million was attributable to the 59% decrease in average natural gas prices received; and
- Volume variances that had a $104.9 million unfavorable impact on sales, with $108.9 million of decreases attributable to the 1.1 million Bbl decrease in oil production volumes, and $1.6 million of decreases attributable to the less than 0.1 million Bbl decrease in NGL production volumes, partially offset by an increase of $5.6 million due to the 0.7 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations excluding any effects of our hedging activities:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
2008:							
First	1,420	316	5.0	2,570	$99.43	$59.80	$7.97
Second	1,482	290	5.5	2,694	$125.20	$67.73	$10.49
Third	1,171	294	5.1	2,319	$122.71	$70.55	$9.70
Fourth	1,347	311	4.9	2,466	$58.70	$32.00	$5.68
Total	5,420	1,211	20.5	10,049	$101.38	$57.15	$8.54
2009:							
First	1,108	307	5.7	2,366	$41.15	$22.52	$4.19
Second	1,026	308	5.5	2,255	$55.42	$28.26	$3.11
Third	1,078	279	5.2	2,219	$68.15	$35.09	$2.84
Fourth	1,134	289	4.8	2,215	$75.09	$40.45	$3.75
Total	4,346	1,183	21.2	9,055	$60.07	$31.36	$3.48
2010:							
First	945	303	4.8	2,045	$78.10	$44.71	$4.74
Second	979	279	4.6	2,028	$77.83	$41.92	$3.72
Third	1,005	256	4.9	2,072	$76.39	$39.88	$3.87
Fourth	976	299	5.5	2,185	$85.52	$42.81	$3.57
Total	3,905	1,137	19.7	8,330	$79.45	$42.44	$3.96

During 2010, 2009, and 2008, we recognized net gains (losses) of $0.7 million, ($1.4) million, and $26.1 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of operations. Had these gains been recognized in the oil and gas sales account, our average oil sales price would have been $79.52, $59.77 and $105.32 for 2010, 2009, and 2008, respectively, and our average natural gas price would have been $3.98, $3.47 and $8.77 for 2010, 2009, and 2008, respectively.

Costs and Expenses.

Our expenses in 2010 decreased $70.9 million, or 16%, compared to 2009 expenses for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $5.2 million, or 7%, compared to the level of such expenses in 2009, while 2009 costs decreased $28.1 million, or 27% over 2008 levels. Lease operating costs increased during 2010 due to higher workover costs and other cost increases from lease supervision and repair & maintenance. These costs decreased in 2009 due to decreases in work-over costs, decreasing costs for industry goods and services, as well as lower natural gas and NGL processing costs. Clean-up and repair costs related to hurricanes Gustav and Ike totaled $3.7 million in 2008. Our lease operating costs per Boe produced were $9.84, $8.47, and $10.44 in 2010, 2009, and 2008, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses decreased $3.5 million, or 2%, in 2010, from 2009 levels and decreased $56.2 million, or 25% in 2009, from 2008 levels. The decrease in 2010 was due to lower production and higher reserves, partially offset by a higher depletion base. The decrease in 2009 was due to the write-down of oil and gas properties in the first quarter of 2009 which lowered our depletable base in addition to lower production, partially offset by lower reserves volumes and higher future development costs. Our DD&A rate per Boe of production was $19.52 in 2010, $18.34 in 2009, and $22.12 in 2008, resulting from increases in per unit cost of reserves additions in 2010 and decreases in per unit costs for 2009.

General and Administrative Expenses. These expenses increased $2.3 million, or 7%, from the level of such expenses in 2009, while 2009 general and administrative expenses, net, decreased $4.6 million, or 12%, from the level of such expenses in 2008. The increase in 2010 was primarily due to higher performance based compensation, partially offset by lower salaries and burdens. The decrease in 2009 was primarily due to lower stock compensation and lower salaries from the workforce reduction in early 2009, partially offset by lower capitalized amounts. For the years 2010, 2009, and 2008, our capitalized general and administrative costs totaled $24.6 million, $24.5 million, and $30.1 million, respectively. Our net general and administrative expenses per Boe produced increased to $4.37 per Boe in 2010 from $3.76 per Boe in 2009, compared to $3.85 per Boe in 2008. The portion of supervision fees recorded as a reduction to general and administrative expenses was $12.5 million for 2010, $11.4 million for 2009, and $15.8 million for 2008.

Severance and other taxes. These expenses increased $4.5 million, or 11%, from 2009 levels, while in 2009 these taxes decreased $39.1 million, or 49%, over 2008 levels. The increases in 2010 were due primarily to higher revenues from higher commodity prices. In 2009 the decreases were caused by lower commodity prices and lower production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 10.5%, 11.1% and 10.1% in 2010, 2009 and 2008, respectively. The decrease in 2010 was primarily driven by a shift in product and regional mix as well as reduced tax rates for tight sand gas production related to South Texas Olmos and Eagle Ford completions. The increase in 2009 was caused by an increase in rates on Louisiana natural gas, which increased approximately 10% per Mcf produced, along with a slight increase in total revenues from oil production.

Interest. Our gross interest cost in 2010 was $40.8 million, of which $7.4 million was capitalized. Our total interest cost in 2009 was $36.8 million, of which $6.1 million was capitalized. Our total interest cost in 2008 was $39.1 million, of which $8.0 million was capitalized. The increase in interest expense in 2010 was primarily due to higher weighted average interest rates on outstanding debt in 2010 as compared to prior periods.

Income Taxes. Our effective income tax rate was 37.5%, 39.5% and 37.7% for 2010, 2009 and 2008, respectively. Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position

2009 and 2008 Ceiling Test Non-Cash Writedowns. In the first quarter of 2009, as a result of low oil and gas prices at March 31, 2009 we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and natural gas properties. In the fourth quarter of 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and natural gas properties.

Net income (Loss). Our 2010 net income of $46.3 million was significantly improved, as compared to a 2009 net loss of $39.3 million (which included a $79.3 million non-cash write-down of oil and gas properties from the first quarter of 2009) and a 2008 net loss of $260.5 million (principally due to the $754.3 million non-cash write-down of oil and gas properties in December 2008). If the 2009 ceiling test write-down of $79.3 million ($50.0 million after-tax) and 2008 ceiling test write-down of $754.3 million ($473.1 million after tax) were to be excluded from 2009 and 2008 results, 2009's income from continuing operations after tax would have been $11.0 million, while 2008's income from continuing operations after tax would have been $216.0 million.

Known Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and this volatility is expected to continue in future periods. Factors such as worldwide economic conditions and credit availability, worldwide supply disruptions, weather conditions, fluctuating currency exchange rates, and political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices remained high during much of 2008 when compared to longer-term historical prices but began falling in 2008 and continued to fall throughout 2009, showing slight improvement in late 2009 and through 2010. North American weather conditions, the industrial and consumer demand for natural gas, economic conditions and credit availability, storage levels of natural gas, the level of liquefied natural gas imports, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Hurricane activity in the Gulf of Mexico may have a direct impact on our costs and operations. Extreme weather conditions in our Southeast Louisiana areas of activity can increase our costs, adversely affect our operations, and cause equipment or well damage, which damage may not be fully insured, and is no longer being covered by business interruption insurance.

Due to the cyclical nature of the oil and gas industry and during periods of increased levels of exploration and production in particular areas, such as we are currently experiencing in the Olmos and Eagle Ford formations, there is increased demand for drilling rigs, equipment, supplies, oilfield services, and trained and experienced personnel. The high demand in these areas has caused shortages and delays, which has raised costs and often delayed field development.

We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owner's receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. Credit losses in 2010 and 2009 have been immaterial; we continue to monitor our purchasers of oil and gas for creditworthiness. We believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. For 2010, 2009 and 2008, oil and gas sales to Shell Oil Corporation and affiliates were 52%, 48% and 28% of total oil and gas sales, respectively; Chevron Corporation and its affiliates accounted for 25% of our 2008 total oil and gas sales. From certain customers we also obtain letters of credit or parent company guaranties, if applicable, to reduce risk of loss.

The oil and gas industry is subject to the indirect consequences of regulations that could expose us to risks of increasing environmental laws and regulations (and possibly increased costs of operations), delays in obtaining permits and licenses, and reduced demand for crude oil and natural gas, among others.

Liquidity and Capital Resources

Capital Expenditures

2010 Capital Expenditures. Our capital expenditures on a cash flow basis during 2010 were $353.6 million, while our accrual based capital expenditures were $421.0 million, as we significantly increased our accounts payable and accrued capital cost balances related to capital expenditures in the second half of 2010. Our cash flow basis amount of capital expenditures increased by $138.3 million as compared to those in the 2009 period mainly due to an increase in our spending on drilling and development in our South Texas core area. These 2010 expenditures were primarily funded by $259.0 million of cash provided by operating activities from continuing operations, and $140.1 million of proceeds from our public stock offering in November 2010.

Sources of Funds

Net Cash Provided by Operating Activities. For 2010, our net cash provided by operating activities from continuing operations was $259.0 million, representing a 15% increase as compared to $226.2 million generated during 2009. The 2010 increase was primarily due to an increase of $68.0 million in revenues, mainly attributable to higher oil and natural gas prices, partially offset by a combination of lower production, higher lease operating costs and higher severance taxes due to higher oil and gas sales. For 2009, our net cash provided by operating activities from continuing operations represented a 61% decrease from the $582.0 million generated during 2008, with this decrease primarily due to a $450.4 million decrease in revenues, mainly attributable to lower oil and natural gas prices in 2009, as well as lower production, partially offset by lower lease operating costs and severance taxes due to lower oil and gas sales.

2011 Capital Expenditures. We currently plan to finance our 2011 accrual based capital expenditures with our 2011 cash flow, cash on hand and potential line of credit borrowings. Our 2011 capital expenditures are currently budgeted at $430 million to $480 million, net of potential dispositions of non-strategic properties. Approximately 80% of our capital budget is targeted for our South Texas core area. The Company may also explore both joint venture arrangements for particular prospects and select property dispositions, in each case to accelerate drilling and development of its assets and diversify its risk profile. For 2011, we are targeting an increase in production volumes of 25% to 30% over 2010 levels and reserves growth of 15% to 20% over 2010 levels.

Existing Credit Facility. In September 2010 we renewed and extended our $500.0 million credit facility through October 2015,increasing our borrowing base to $300.0 million from $277.5 million. We had no amounts drawn under our credit facility at year-end of both 2009 and 2010. The next scheduled borrowing base review occurs in May 2011. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement and expect to remain in compliance with these provisions in future periods. Our available borrowings under our line of credit facility provide us liquidity. In light of credit market volatility in recent years which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

2010 Public Stock Offering. We raised $140.1 million net through an underwritten public stock offering in November 2010, issuing 4.04 million shares of our common stock at a price of $36.60 per share. The gross proceeds from these sales were approximately $147.8 million, before deducting underwriting commissions and issuance costs totaling $7.7 million. We used the proceeds from this stock sale to expand our South Texas drilling program and pay down a portion of the outstanding balance on our credit facility which increased liquidity.

2009 Public Stock Offering. We raised $108.8 million net through an underwritten public stock offering in August 2009, issuing 6.21 million shares of our common stock at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million. We used the proceeds from this stock sale to pay down a portion of the outstanding balance on our credit facility which increased liquidity.

2009 Debt Issuance and Debt Retirements. We issued $225.0 million of 8-7/8% senior notes due 2020 in November 2009. In December 2009, we redeemed all $150.0 million of 7-5/8% senior notes due 2011 and recorded a charge of $4.0 million related to the redemption of these notes, which is recorded in "Debt retirement costs" on the accompanying consolidated statement of operations.

Financial Ratios

Working Capital and Debt to Capitalization. Our working capital increased from a surplus of $5.0 million at December 31, 2009, to a deficit of $2.0 million at December 31, 2010. The change primarily resulted from an increase in accounts payable and accrued liabilities plus an increase in accrued capital costs all of which are related to additional drilling activity in South Texas during 2010. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our debt to capitalization ratio decreased to 35% at December 31, 2010, as compared to 41% at year-end 2009, as paid in capital increased due to our November 2010 stock offering, along with an increase in retained earnings due to our net income for 2010.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2010 are as follows:

	2011	2012	2013	2014 (in thousands)	2015	Thereafter	Total
Non-cancelable operating leases (1)	$5,985	$5,787	$5,632	$5,615	$936	—	$23,955
Asset retirement obligation (2)	8,708	3,513	2,773	2,615	3,350	57,920	78,879
Drilling rigs and completion services	75,545	25,184	—	—	—	—	100,729
Gas transportation (3)	1,388	1,879	2,325	2,595	—	—	8,187
7-1/8% senior notes due 2017	—	—	—	—	—	250,000	250,000
8-7/8% senior notes due 2020	—	—	—	—	—	225,000	225,000
Interest Cost	37,781	37,781	37,781	37,781	37,781	116,578	305,483
Credit facility (4)	—	—	—	—	—	—	—
Total	$129,407	$74,144	$48,511	$48,606	$42,067	$649,498	$992,233

(1) Our most significant office lease is in Houston, Texas and it extends until 2015.
(2) Amounts shown by year are the net present value at December 31, 2010.
(3) Amounts shown represent fees for the minimum delivery obligations. Any amount of transportation utilized in excess of the minimum will reduce future year obligations
(4) The credit facility expires in October 2015 and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

As of December 31, 2010 we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Proved Oil and Gas Reserves

We have added proved reserves over the past three years primarily through our drilling activities, including 36.7 MMBoe added in 2010, 8.5 MMBoe added in 2009, and 5.7 MMBoe added in 2008. The 2010 proved reserves additions from drilling activities consisted primarily of 30.2 MMBoe of additions to reserves in our South Texas area and 6.4 MMBoe of additions in the Burr Ferry Field. These additions were primarily proved undeveloped additions based on the results of the horizontal drilling program conducted in these areas during the year and would have been recorded as reserves additions under both the former and revised SEC reserves regulations. We obtained reasonable certainty regarding these reserves additions by applying the same methodologies that have been used historically in this area. We did not record material proved reserves revisions during 2010 as a result of the revised SEC reserves regulations. At year-end 2010, 45% of our total proved reserves were proved developed, compared with 50% at year-end 2009 and 53% at year-end 2008.

At year-end 2010, our proved reserves were 132.8 MMBoe with a PV-10 Value of $1.8 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure), an increase in PV-10 of approximately $450 million from the prior year-end levels. In 2010, our proved natural gas reserves increased 132.4 Bcf, or 46%, while our proved oil reserves decreased 5.2 MMBbl, or 12%, and our NGL reserves increased 2.9 MMBbl, or 15%, for a total equivalent increase of 19.9 MMBoe, or 18%.

At year-end 2009, our proved reserves were 112.9 MMBoe with a PV-10 Value of $1.3 billion. In 2009, our proved natural gas reserves decreased 1.8 Bcf, or 1%, while our proved oil reserves decreased 5.2 MMBbl, or 10%, and our NGL reserves increased 2.0 MMBbl, or 11%, for a total equivalent decrease of 3.5 MMBoe, or 3%.

Our average natural gas price used in the PV-10 calculation for 2010 was $4.08 per Mcf. This average price during 2010 was a decrease from $3.78 per Mcf at year-end 2009, compared to $4.96 per Mcf at year-end 2008. Our average oil price used in the PV-10 calculation for 2010 was $78.31 per Bbl. This average price during 2010 was an increase from $59.76 per Bbl at year-end 2009, compared to $44.09 in 2008.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. This calculation is done on a country-by-country basis.

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). We did not have any outstanding derivative instruments at December 31, 2010 that would materially affect this calculation.

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. See the discussion above related to reserves estimation.

In 2009, as a result of lower oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and gas properties. In the fourth quarter of 2008, we reported a non-cash write-down on a before-tax basis of $754.3 million ($473.1 million after tax) on our oil and gas properties due to lower oil and natural gas prices at the end of 2008.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near-term. If oil and natural gas prices continue to decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur."

New Accounting Pronouncements. In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic 932 ("Extractive Industries – Oil and Gas") with the requirements of SEC release 33-8995. These releases are effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves is allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC for Form 10-K.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

These new requirements did not have a material impact upon our reserves estimation or earnings in the current period. The new rule requiring the preceding 12-month's average price for oil and natural gas resulted in a lower average price for our reserves calculations for 2010 than if we had used the previous method utilizing the current price at period-end. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

Forward-Looking Information

The statements contained in this Annual Report on Form 10-K that are not historical facts, not limited to, statements found in “Business and Properties” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” are forward-looking statements as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, acquisition plans and proposals and dispositions, development activities, cost savings, capital budgets, production rates and volumes or forecasts thereof, hydrocarbon reserves, hydrocarbon prices, pricing or cost assumptions based on current and projected oil and gas prices, liquidity, cash flows, availability of capital, borrowing capacity, acquisition plans, regulatory matters, prospective legislation affecting the oil and gas industry, competition, long-term forecasts of production, finding costs, rates of return, estimated costs, or changes in costs, future capital expenditures and overall economics and other variables surrounding our operations and future plans. Such forward-looking statements generally are accompanied by words such as “plan,” “future,” “estimate,” “expect,” “budge “predict,” “anticipate,” “projected,” “should,” “assume,” “believe,” “target” or other words that convey the uncertainty o events or outcomes. Such forward-looking information is based upon management’s current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company’s financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company’s oil and natural gas; effects of our indebtedness; success of our risk management techniques; inaccurate cost estimates; availability of and fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards; disruption of operations and damages from hurricanes or tropical storms; acquisition risks; requirements for capital or its availability; conditions in the financial and credit markets; general economic conditions; changes in geologic or engineering information; competition and government regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or which are otherwise discussed in this annual report, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in the Company’s other public reports, filings, and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Significant declines in oil and natural gas prices began in the last half of 2008, and such pricing volatility has continued through 2009 with some improvement during the last half of 2009 and into 2010.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

Price Floors – Between October and December 2010 we entered into additional natural gas price floors. These price floors cover natural gas production for January to April 2011 of 4,250,000 MMBtu with strike prices ranging between $3.77 and $4.30 per MMBtu.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2010, we had no borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our 2010 cash flows.

Income Tax Carryforwards. As of December 31, 2010, the Company has net tax carryforward assets of $23.1 million for federal net operating losses, $2.1 for federal alternative minimum tax credits and $7.8 million, net of a $1.7 million valuation allowance, for state tax net operating loss carryforwards which in management's judgment will more likely than not be utilized to offset future taxable earnings. The Internal Revenue Service (IRS) commenced an examination of the Company's 2008 U.S. income tax returns in October 2010.

The Company's New Zealand subsidiaries have local income tax loss carryovers which are available if any future income is generated by these entities. As of December 31, 2010 the estimated U.S. dollar value of these loss carryover assets is $34.2 million. In management's judgment it is less than more likely than not that the remaining carryover assets will be utilized. Accordingly, these carryover assets have been fully offset by a valuation allowance.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2010 and 2009, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2010 and 2009, the fair value of our senior notes due 2017, was 254.7 million, or 101.9% of face value, and $239.1 million, or 95.6% of face value, respectfully. Based upon quoted market prices as of December 31, 2010 and 2009, the fair value of our senior notes due 2020, which were issued in November 2009, was $242.3 million, or 107.7% of face value and $234.0 million, or 104% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2010 and 2009, while the carrying value of our senior notes due 2020 was $221.6 million and $221.4 million at December 31, 2010 and 2009, respectively.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers from certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Management's Report on Internal Control Over Financial Reporting

Management of Swift Energy Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with U. S. generally accepted accounting principles.

Management of the Company assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control—Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2010.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance of achieving their control objectives. 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.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2010, based on their audit. The Public Company Accounting Oversight Board (United States) standards require that they plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Their audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as they considered necessary in the circumstances.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited Swift Energy Company and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, 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 its 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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 the Company as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010 and our report dated February 24, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 24, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries (the “Company”) as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 24, 2011

Consolidated Balance Sheets
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Year Ended December 31, 2010	2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$86,367	$38,469
Accounts receivable	46,975	54,273
Deferred tax assets	8,806	3,171
Other current assets	18,105	12,123
Current assets held for sale	564	564
Total Current Assets	160,817	108,600
Property and Equipment:		
Property and Equipment	3,951,107	3,530,110
Less – Accumulated depreciation, depletion, and amortization	(2,378,262)	(2,214,146)
Property and Equipment, Net	1,572,845	1,315,964
Other Long-Term Assets	12,713	10,201
Total Assets	1,746,375	$1,434,765
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$81,646	$60,823
Accrued capital costs	64,879	33,199
Accrued interest	11,010	3,745
Undistributed oil and gas revenues	5,252	5,837
Total Current Liabilities	162,787	103,604
Long-Term Debt	471,624	471,397
Deferred Income Taxes	160,024	123,577
Asset Retirement Obligation	70,171	55,298
Other Long-Term Liabilities	1,752	1,990
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, $.01 par value, 85,000,000 shares authorized, 42,440,583 and 37,887,126 shares issued, and 41,999,058 and 37,456,603 shares outstanding respectively	424	379
Additional paid-in capital	706,857	551,606
Treasury stock held, at cost, 441,525 and 430,523 shares, respectively	(9,778)	(9,221)
Retained earnings	182,652	136,358
Accumulated other comprehensive loss, net of income tax	(138)	(223)
Total Stockholders' Equity	880,017	678,899
Total Liabilities and Stockholders' Equity	$1,746,375	$1,434,765

See accompanying notes to consolidated financial statements.

Consolidated Statements of Operations
Swift Energy Company and Subsidiaries
(in thousands, except share amounts)

	Year Ended December 31,		
	2010	2009	2008
Revenues:			
Oil and gas sales	$436,632	$371,749	$793,859
Price-risk management and other, net	1,797	(1,304)	26,956
Total Revenues	438,429	370,445	820,815
Costs and Expenses:			
General and administrative, net	36,359	34,046	38,673
Depreciation, depletion, and amortization	162,572	166,108	222,288
Accretion of asset retirement obligation	3,956	2,906	1,958
Lease operating cost	81,929	76,740	104,874
Severance and other taxes	45,868	41,326	80,403
Interest expense, net	33,437	30,663	31,079
Debt retirement cost	---	3,961	---
Write-down of oil and gas properties	---	79,312	754,298
Total Costs and Expenses	364,121	435,062	1,233,573
Income (Loss) from Continuing Operations Before Income Taxes	74,308	(64,617)	(412,758)
Provision (Benefit) for Income Taxes	27,833	(25,541)	(155,628)
Income (Loss) from Continuing Operations	46,475	(39,076)	(257,130)
Loss from Discontinued Operations, net of taxes	(181)	(254)	(3,360)
Net Income (Loss)	$46,294	$(39,330)	$(260,490)
Per Share Amounts-			
Basic: Income (Loss) from Continuing Operations	$1.19	$(1.16)	$(8.39)
Loss from Discontinued Operations, net of taxes	(0.00)	(0.01)	(0.11)
Net Income (Loss)	$1.19	$(1.17)	$(8.50)
Diluted: Income (Loss) from Continuing Operations	$1.18	$(1.16)	$(8.39)
Loss from Discontinued Operations, net of taxes	(0.00)	(0.01)	(0.11)
Net Income (Loss)	$1.18	$(1.17)	$(8.50)
Weighted Average Shares Outstanding	38,300	33,594	30,661

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries
(in thousands, except per share amounts)

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2007	$306	$407,464	$(7,480)	$436,178	$ (414)	$836,054
Stock issued for benefit plans (39,152 shares)	-	1,018	671	-	-	1,689
Stock options exercised (420,721 shares)	4	8,295	-	-	-	8,299
Purchase of treasury shares (70,622 shares)	-	-	(3,622)	-	-	(3,622)
Tax benefits from stock compensation	-	1,422	-	-	-	1,422
Employee stock purchase plan (25,645 shares)	-	944	-	-	-	944
Issuance of restricted stock (275,096 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	16,167	-	-	-	16,167
Net loss	-	-	-	(260,490)	-	(260,490)
Other comprehensive income	-	-	-	-	414	414
Total comprehensive loss						(260,076)
Balance, December 31, 2008	$313	$435,307	$(10,431)	$175,688	$ -	$600,877
Stock issued for benefit plans (94,023 shares)	-	(716)	2,094	-	-	1,378
Stock options exercised (26,056 shares)	-	326	-	-	-	326
Public Stock offering (6,210,000 shares)	62	108,689	-	-	-	108,751
Purchase of treasury shares (56,662 shares)	-	-	(884)	-	-	(884)
Tax benefits from stock compensation	-	(4,041)	-	-	-	(4,041)
Employee stock purchase plan (50,690 shares)	1	724	-	-	-	725
Issuance of restricted stock (263,908 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	11,320	-	-	-	11,320
Net loss	-	-	-	(39,330)	-	(39,330)
Other comprehensive loss	-	-	-	-	(223)	(223)
Total comprehensive loss						(39,553)
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$ (223)	$678,899

Stock issued for benefit plans (59,335 shares)	-	242	1,271	-	-	1,513
Stock options exercised (136,432 shares)	1	2,086	-	-	-	2,087
Public Stock offering (4,038,270 shares)	40	140,099	-	-	-	140,139
Purchase of treasury shares (70,337 shares)	-	-	(1,828)	-	-	(1,828)
Tax benefits from stock compensation	-	28	-	-	-	28
Employee stock purchase plan (66,564 shares)	1	950	-	-	-	951
Issuance of restricted stock (312,191 shares)	3	(3)	-	-	-	-
Amortization of stock compensation	-	11,849	-	-	-	11,849
Net Income	-	-	-	46,294	-	46,294
Other comprehensive income	-	-	-	-	85	85
Total comprehensive income						46,379
Balance, December 31, 2010	$424	$706,857	$(9,778)	$182,652	$ (138)	$880,017

(1) $.01 par value.

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries
(in thousands)

	Year Ended December 31,		
	2010	2009	2008
Cash Flows from Operating Activities:			
Net income (loss)	$46,294	$(39,330)	$(260,490)
Plus loss from discontinued operations, net of taxes	181	254	3,360
Adjustments to reconcile net income (loss) to net cash provided by operation activities -			
Depreciation, depletion, and amortization	162,572	166,108	222,288
Write-down of oil and gas properties	-	79,312	754,298
Accretion of asset retirement obligation	3,956	2,906	1,958
Deferred income taxes	32,881	(13,377)	(164,498)
Stock-based compensation expense	10,256	9,232	11,631
Debt retirement cost – cash and non-cash	---	3,961	---
Other	1,563	16,133	(8,640)
Change in assets and liabilities-			
(Increase) decrease in accounts receivable	(6,691)	2,666	26,172
Increase (decrease) in accounts payable and accrued liabilities	472	1,977	(3,915)
Increase (decrease) in income taxes payable	247	(204)	214
Increase (decrease) in accrued interest	7,265	(3,462)	(351)
Cash provided by operating activities – continuing operations	258,996	226,176	582,027
Cash provided by (used in) operating activities – discontinued operations	(41)	(396)	6,039
Net Cash Provided by Operating Activities	258,955	225,780	588,066
Cash Flows from Investing Activities:			
Additions to property and equipment	(353,648)	(215,370)	(628,325)
Proceeds from the sale of property and equipment	133	31,083	144
Acquisition of properties	---	---	(46,472)
Cash used in investing activities – continuing operations	(353,515)	(184,287)	(674,653)
Cash provided by investing activities – discontinued operations	5,000	5,000	80,504
Net Cash Used in Investing Activities	(348,515)	(179,287)	(594,149)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	---	221,375	---
Payments of long-term debt	---	(150,000)	---
Net payments of bank borrowings	---	(180,700)	(6,300)
Net proceeds from issuances of common stock	142,917	109,801	9,243
Excess tax benefits from stock-based awards	---	---	1,422
Purchase of treasury shares	(1,828)	(884)	(3,622)
Payments of debt retirement costs	---	(2,859)	---
Payments of debt issuance costs	(3,631)	(5,040)	---
Cash provided by (used in) financing activities – continuing operations	137,458	(8,307)	743
Cash provided by financing activities – discontinued operations	---	---	---
Net Cash provided by (used in) financing activities	137,458	(8,307)	743
Net Increase (decrease) in Cash and Cash Equivalents	$47,898	$38,186	$(5,340)

Cash and Cash Equivalents at Beginning of Year	38,469	283	5,623
Cash and Cash Equivalents at End of Year	$86,367	$38,469	$283
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$24,622	$32,885	$30,283
Cash paid during year for income taxes	$200	$233	$8,505

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in gas processing plants are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Discontinued Operations. Unless otherwise indicated, information presented in the notes to the financial statements relates only to Swift Energy's continuing operations. Information related to discontinued operations is included in Note 8 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

Subsequent Events. We have evaluated subsequent events of our consolidated financial statements. There were no material subsequent events requiring additional disclosure in or amendments to these financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations, and
- estimates in the calculation of the fair value of hedging assets.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2010, 2009, and 2008, such internal costs capitalized totaled $24.6 million, $24.5 million, and $30.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2010, 2009, and 2008, capitalized interest on unproved properties totaled $7.4 million, $6.1 million, and $8.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

The "Property and Equipment" balances on the accompanying consolidated balance sheets are summarized for presentation purposes. The following is a detailed breakout of our "Property and Equipment" balances.

Property and Equipment (in thousands)	December 31, 2010	December 31, 2009
Property and Equipment		
Proved oil and gas properties	$ 3,835,173	$ 3,421,340
Unproved oil and gas properties	78,429	71,640
Furniture, fixtures, and other equipment	37,505	37,130
Less – Accumulated depreciation, depletion, and amortization	(2,378,262)	(2,214,146)
Property and Equipment, Net	$ 1,572,845	$ 1,315,964

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and natural gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced during the period by the total estimated units of proved oil and natural gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between 2 and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical ("G&G") costs incurred on developed properties are recorded in "Proved properties" and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in "Unproved properties" and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (“Ceiling Test”). Our hedges at year-end 2010 consisted of natural gas price floors that did not materially affect prices used in these calculations. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization (“DD&A”) is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

In 2009, as a result of low oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million on our oil and natural gas properties. For 2008, as a result of low oil and natural gas prices at December 31, 2008, we reported a fourth quarter non-cash write-down on a before-tax basis of $754.3 million on our oil and natural gas properties.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices decline from our prices used in the Ceiling Test, it is possible that additional non-cash write-downs of oil and natural gas properties could occur in the future. If we have significant declines in our oil and natural gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and natural gas reserves, additional non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets. Natural gas balancing receivables are reported in “Other current assets” on the accompanying consolidated balance sheets when our ownership share of production exceeds sales. As of December 31, 2010, we did not have any material natural gas imbalances.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2010 and 2009, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2010 and 2009, the fair value of our senior notes due 2017, was 254.7 million, or 101.88% of face value, and $239.1 million, or 95.6% of face value, respectfully. Based upon quoted market prices as of December 31, 2010 and 2009, the fair value of our senior notes due 2020, which were issued in November 2009, was $242.3 million, or 107.7% of face value and $234.0 million, or 104% of face value, respectively. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2010 and 2009, while the carrying value of our senior notes due 2020 was $221.6 million and $221.4 million at December 31, 2010 and 2009, respectively.

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2010 and 2009, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balance on the accompanying consolidated balance sheets.

At December 31, 2010 our “Accounts receivable” balance included $43.3 million for oil and gas sales, $2.3 million for joint interest owners and $1.4 million for other receivables. At December 31, 2009 our “Accounts receivable” balance included $36.4 million for oil and gas sales, $2.6 million for joint interest owners and $15.3 million for other receivables.

Debt Issuance Costs. Legal fees, accounting fees, underwriting fees, printing costs, and other direct expenses associated with extensions of our bank credit facility and public debt offerings were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility.

The 7-1/8% senior notes due 2017 mature on June 1, 2017, and the balance of their issuance costs at December 31, 2010, was $3.0 million, net of accumulated amortization of $1.2 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at December 31, 2010, was $4.7 million, net of accumulated amortization of $0.3 million. The issuance costs associated with our revolving credit facility, which was extended in September 2010, had been capitalized and is being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2010, was $3.7 million, net of accumulated amortization of $3.2 million.

Insurance Claims. In 2008, we filed insurance claims related to 2008 Hurricanes Gustav and Ike. In April 2009, we settled our marine insurance claim relating to Hurricane Gustav for a net amount after deductible of $6.8 million, and in September 2009 settled our onshore claim relating to Hurricane Ike for a net amount after deductible of $0.8 million. Both of these reimbursements related to both capital costs and lease operating expense, and we have no additional hurricane related claims outstanding.

We have several open insurance claims filed in the ordinary course of business, none of which are material at the present time.

Price-Risk Management Activities. The Company follows FASB ASC 815-10, which requires that changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the consolidated balance sheets as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors and collars. During 2010, 2009, and 2008, we recognized net gains (losses) of $0.7 million, ($1.4) million, and $26.1 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations. Had these gains and losses been recognized in the oil and gas sales account they would not materially change our per unit sales prices received. At December 31, 2010, the Company had recorded $0.1 million, net of taxes of less than $0.1 million, of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying consolidated balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for the twelve months of 2010 and 2009 was not material. All amounts currently held in "Accumulated other comprehensive loss, net of income tax" will be realized within the next four months when the forecasted sale of hedged production occurs.

At December 31, 2010, we had natural gas price floors in effect that covered a portion of our natural gas production for January to April 2011. These floors cover production of 4,250,000 MMBtu from January through April 2011 with strike prices ranging between $3.77 and $4.30 per MMBtu.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive loss, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive loss, net of income tax" on the accompanying consolidated balance sheets and recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations. The fair values of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2010 and 2009, was $0.3 million and $0.8 million, respectively, and was recognized on the accompanying consolidated balance sheets in "Other current assets." At December 31, 2010, we had less than $0.1 million in receivables for settled gas hedges covering January 2011 production which are recognized on the accompanying balance sheet in "Accounts Receivables" and were subsequently collected in January 2011.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees, to the extent they do not exceed actual costs incurred, are recorded as a reduction to “General and administrative, net.” Our supervision fees are based on COPAS guidelines. The amount of supervision fees charged in 2010 and 2009 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $12.5 million in 2010, $11.4 million in 2009, and $15.8 million in 2008.

Inventories. Inventories consist primarily of tubulars and other equipment that we expect to place in service in production operations. Inventories carried at cost (weighted average method) and are included in “Other current assets” on the accompanying consolidated balance sheets totaling $12.8 million and $10.0 million at December 31, 2010 and 2009, respectively.

Income Taxes. Under guidance contained in FASB ASC 740-10, deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. As a result of adopting this guidance on January 1, 2007, we reported a $1.0 million decrease to our January 1, 2007 retained earnings balance and a corresponding increase to other long-term liabilities If recognized, these tax benefits would fully impact our effective tax rate

We do not believe the total of unrecognized tax positions will significantly increase or decrease during the next 12 months.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of December 31, 2010, we did not have any amount accrued for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns for 2002 forward, our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2004, and our Texas franchise tax returns after 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other state returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. Included in “Accounts payable and accrued liabilities,” on the accompanying consolidated balance sheets, at December 31, 2010 and 2009 are trade payables of approximately $13.7 million and $2.7 million, respectively and accrued employee bonus and benefit payables of $11.5 million and $9.6 million. Also included are liabilities of approximately $8.1 million and $7.5 million at December 31, 2010 and 2009 respectively for outstanding checks. This represents the amounts by which checks issued, but not presented by vendors to the Company’s banks for collection, exceeded balances in the applicable disbursement bank accounts.

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents.

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners’ receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. From certain customers we also obtain letters of credit or parent company guaranties, if applicable, to reduce risk of loss. During 2010, 2009 and 2008, oil and gas sales to Shell Oil Company and affiliates accounted for 52%, 48% and 28% of our gross receipts, respectively. During 2008 sales to Chevron Corporation and its affiliates accounted for 25% of our total oil and gas receipts. Credit losses in each of the last three years were immaterial.

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of December 31, 2010 and 2009 these assets include approximately $1.3 million. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields. Restricted cash balances are reported in "Other long-term assets" on the accompanying consolidated balance sheets.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2010, we recorded $0.1 million, net of taxes of less than $0.1 million, of derivative losses in "Accumulated other comprehensive loss, net of income tax" on the accompanying consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2010 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2009	$ (354)	$ 131	$ (223)
Change in fair value of cash flow hedges	868	(319)	549
Effect of cash flow hedges settled during the period	(732)	269	(463)
Other comprehensive loss at December 31, 2010	$ (218)	$ 81	$ (137)

Total comprehensive income (loss) was $46.4 million, ($39.6) million and ($260.1) million for 2010, 2009, and 2008, respectively.

Asset Retirement Obligation. We record these obligations in accordance with the guidance contained in FASB ASC 410-20. This guidance requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the estimated oil and natural gas reserves of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the full cost balance. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

The following provides a roll-forward of our asset retirement obligation (in thousands):

Asset Retirement Obligation as of December 31, 2007	$34,459
Accretion expense	1,958
Liabilities incurred for new wells and facilities construction	1,985
Liabilities incurred for acquisitions	218
Reductions due to sold and abandoned wells	(515)
Revisions in estimated cash flows	10,680
Asset Retirement Obligation as of December 31, 2008	$48,785
Accretion expense	2,906
Liabilities incurred for new wells and facilities construction	3,400
Reductions due to sold and abandoned wells	(1,380)
Revisions in estimated cash flows	10,525
Asset Retirement Obligation as of December 31, 2009	$64,236
Accretion expense	3,956
Liabilities incurred for new wells and facilities construction	1,287
Reductions due to sold and abandoned wells	(749)
Revisions in estimated cash flows	10,149
Asset Retirement Obligation as of December 31, 2010	$78,879

At December 31, 2010 and 2009, we had $8.7 million and $8.9 million, respectively, of our asset retirement obligation classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets.

Public Stock Offering. In November 2010, we issued 4.04 million shares of our common stock in an underwritten public offering at a price of $36.60 per share. The gross proceeds from these sales were approximately $147.8 million, before deducting underwriting commissions and issuance costs totaling $7.7 million.

In August 2009, we issued 6.21 million shares of our common stock in an underwritten public offering at a price of $18.50 per share. The gross proceeds from these sales were approximately $114.9 million, before deducting underwriting commissions and issuance costs totaling $6.1 million.

New Accounting Pronouncements. In January 2010, the FASB issued ASU 2010-03 to amend oil and gas reserve accounting and disclosure guidance that aligns the oil and gas reserve estimation and disclosure requirements of Topic 932 ("Extractive Industries – Oil and Gas") with the requirements of SEC Release No. 33-8995. This release is effective for financial statements issued on or after January 1, 2010. We have adopted this guidance for all reporting periods ending on or after December 31, 2009. This release changes the accounting and disclosure requirements surrounding oil and natural gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The most significant changes include:

- Changes to prices used in reserves calculations, for use in both disclosures and accounting impairment tests. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
- Disclosure of probable and possible reserves is allowed.
- The estimation of reserves will allow the use of reliable technology that was not previously recognized by the SEC.
- Numerous changes in reserves disclosures mandated by SEC Form 10-K.
- Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

These new requirements did not have a material impact upon our reserves estimation or earnings in the current period. These changes could have a material impact upon our financial statements in future periods due to the uncertainty of oil and gas prices.

2. Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Under the guidance, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings. Unvested share-based payments that contain non-forfeitable rights to dividends or dividend equivalents are now included in the basic weighted average share calculation under the two-class method.

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. Diluted EPS for the year ended December 31, 2010 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. As we recognized a net loss for the years ended December 31, 2009 an 2008, the unvested share-based payments and stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the year ended December 31, 2010, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per share amounts):

	2010			2009			2008		
	Income (Loss) from continuing operations	Shares	Per Share Amount	Loss from continuing operations	Shares	Per Share Amount	Income from continuing operations	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) from continuing operations, and share Amounts	$46,475	38,300		$(39,076)	33,594		$(257,130)	30,661	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	(879)	---		---	---		---	---	
Income (Loss) from continuing operations allocated to common shares	$45,596	38,300	$1.19	$(39,076)	33,594	$(1.16)	$(257,130)	30,661	$(8.39)
Dilutive Securities:									
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	879								
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders									

Stock Options	(874)	224		--	--		--	--	
Diluted EPS:									
Net Income (Loss) from continuing operations, and assumed share conversions	$45,601	38,524	$1.18	$(39,076)	33,594	$(1.16)	$(257,130)	30,661	$(8.39)

Options to purchase approximately 1.4 million shares at an average exercise price of $29.67 were outstanding at December 31, 2010, while options to purchase approximately 1.3 million shares at an average exercise price of $29.72 were outstanding at December 31, 2009, and options to purchase 1.1 million shares at an average exercise price of $33.22 were outstanding at December 31, 2008. Approximately 0.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the year ended December 31, 2010, because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. All of the 1.3 million and 1.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2009 and 2008, respectively, as they would be antidilutive given the net loss from continuing operations.

Employee restricted stock grants of less than 0.1 million shares were not included in the computation of Diluted EPS for the year ended December 31, 2010, because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under the treasury stock method was greater than the average closing market price for the common shares during that period. All of the 0.7 million and 0.6 million shares of employee restricted stock outstanding at December 31, 2009 and 2008, respectfully, were not included in the computation Diluted EPS, as they would be antidilutive given the net loss from continuing operations.

3. Provision (Benefit) for Income Taxes

Income (Loss) from continuing operations before taxes is as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Income (Loss) from Continuing Operations Before Income Taxes	$ 74,308	$ (64,617)	$ (412,758)

The following is an analysis of the consolidated income tax provision (benefit) (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Current	$ (2,957)	$ (10,792)	$ 5,923
Deferred	30,790	(14,749)	(161,551)
Total	$ 27,833	$ (25,541)	$ (155,628)

Current taxes are primarily U.S. Federal income taxes. For 2010 current income tax expense is a net credit due to realization of U.S. Federal income tax refunds that were not anticipated at the end of 2009. These refunds were realized as a result of provisions within the Work, Homeownership, and Business Assistance Act of 2009 which allowed the Company to carry back its 2008 Federal net operating loss four years. The refunds were attributable to reductions in alternative minimum tax previously paid. The Company has no continuing operations in foreign jurisdictions.

Reconciliations of income taxes computed using the U.S. Federal statutory rate to the effective income tax rates are as follows (in thousands):

	2010	2009	2008
Income taxes (or benefits) computed at U.S. statutory rate (35%)	$ 26,008	$ (22,616)	$ (144,465)
State tax provisions (benefits), net of federal benefits	641	(1,956)	(11,985)
Cumulative impact of adjustments to net	(1,718)	---	---

state income tax rate			
Valuation allowance of carryover tax assets	1,681	(1,082)	---
Non-deductible equity compensation	867	105	823
Other, net	354	8	(1)
Provision (benefit) for income taxes	$ 27,833	$ (25,541)	$ (155,628)
Effective rate	37.5 %	39.5 %	37.7 %

The primary upward adjustments in the effective tax rate above the U.S. statutory rate are the provision for state income taxes (computed net of the offsetting federal benefit) and non-deductible equity compensation. The provision for state income tax was a charge of $0.6 million for 2010 and a credit of $2.0 million and $12.0 million for 2009 and 2008, respectively. Non-deductible equity compensation increased tax expense by $0.9 million for 2010, $0.1 million for 2009, and by $0.8 million for 2008. In 2010 the Company revised its long-term state apportionment rates which resulted in a $1.7 million reduction to state income tax deferred liabilities. However, this adjustment also reduced our future expectation to realize benefits for Louisiana state tax loss carryovers. Accordingly we took a $1.7 million charge for a valuation allowance against our Louisiana loss carryovers. In 2009 the Company was able to reverse a previously recorded $1.1 million valuation allowance as a result of a tax gain realized on a joint venture transaction.

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2010 and 2009 were as follows (in thousands):

	2010	2009
Deferred tax assets:		
Federal net operating losses ("NOLs")	$ 30,715	$ 28,192
NOLs for excess stock-based compensation	(7,590)	(6,909)
Alternative minimum tax credits	2,092	5,364
Carryover items, net of valuation allowance	8,823	9,370
Unrealized stock compensation	5,519	4,861
Other	7,026	6,016
Total deferred tax assets	$ 46,585	$ 46,894
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ (195,454)	$ (165,316)
Other	(2,349)	(1,984)
Total deferred tax liabilities	$ (197,803)	$ (167,300)
Net deferred tax liabilities	$ (151,218)	$ (120,406)
Net current deferred tax assets	8,806	3,171
Net non-current deferred tax liabilities	$ (160,024)	$ (123,577)

Deferred tax assets decreased by $0.3 million. The federal net operating loss tax assets, net of NOLs for excess stock-based compensation, increased by $1.8 million due to a current year tax operating loss. Other items (consisting primarily of expenses accrued for books that are not currently deductible for tax) increased by $1.0 million; these increases were offset by the reduction in the alternative minimum tax credits, primarily the result of the Federal income tax refunds noted previously.

The total change in the deferred liability from 2009 to 2010 was an increase of $30.5 million. This increase is primarily attributable to a $30.1 million increase in the deferred liability for oil and gas exploration and development costs. This increase is primarily attributable to accelerated tax deductions for oil and natural gas exploration and development costs.

The federal net operating losses will expire between 2027 and 2030 if not utilized in earlier periods. The Company's federal NOL tax assets for 2010 and 2009 were $30.7 million and $28.2 million, respectively, including deductions for excess stock-based compensation deductions. Excess stock-based compensation deductions in the amount of $7.6 million for 2010 and $6.9 million for 2009 represent stock-based compensation that have generated tax deductions that have not yet resulted in a cash tax benefit because the Company has NOL carryforwards. The Company plans to recognize the federal NOL tax assets associated with excess stock-based compensation tax deductions only when all other components of the federal NOL tax assets have been fully utilized. If and when the excess stock-based compensation related NOL tax assets are realized, the benefit will be credited directly to equity. The other primary carryover item is a $7.8 million net asset, net of a $1.7 million valuation allowance for State of Louisiana net operating loss carryovers. These loss carryforwards are scheduled to expire between 2013 and 2025.

Unrealized stock compensation accounts for $5.5 million in deferred tax assets. These amounts are attributable to stock compensation expenses accrued for employee stock options and restricted stock that are not realized for income tax purposes until exercised (for stock options) or vested (for restricted stock). The actual tax deductions realized may be significantly different than the accrued amounts depending on the market value of the stock on the date of exercise or vesting.

4. Long-Term Debt

Our long-term debt as of December 31, 2010 and 2009 is as follows (in thousands):

	2010	2009
Bank Borrowings	$ ---	$ ---
7-1/8% senior notes due 2017	250,000	250,000
8-7/8% senior notes due 2020	221,624	221,397
Long-Term Debt	$ 471,624	$ 471,397

The maturities on our long-term debt are $250.0 million in 2017 and $225.0 million in 2020.

We have capitalized interest on our unproved properties in the amount of $7.4 million, $6.1 million and $8.0 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Bank Borrowings. In September 2010 we renewed and extended our $500.0 million credit facility with a syndicate of nine banks through October 15, 2015, and have included a feature that allows the Company to increase the aggregate facility amount available up to $700.0 million with additional commitments from the lenders. We also increased our borrowing base to $300.0 million from $277.5 million. Debt issuance costs of approximately $3.6 million related to the extension of the credit facility were capitalized and are being amortized over the life of the facility.

At December 31, 2010 and 2009 we had no borrowings under our $500.0 million credit facility. The interest rate on our credit facility is either (a) the lead bank's prime plus an applicable margin or (b) LIBOR plus an applicable margin. However with respect to (a) , if the lead bank's prime rate is not higher than each of the federal funds rate plus ½%, and the adjusted London Interbank Offered Rate ("LIBOR") plus 1%, the greatest of these three rates will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 100 to 200 basis points above the Alternative Base Rate and escalating rates of 200 to 300 basis points for LIBOR loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At December 31, 2010, the lead bank's prime rate was 3.25%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. Under the terms of the credit facility, we can increase the commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The borrowing base amount is re-determined at least every six months starting with the next scheduled borrowing base review in May 2011.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.9 million in 2010, $5.2 million in 2009, and $8.6 million in 2008. The amount of commitment fees included in interest expense, net was $1.4 million in 2010, $0.7 million in 2009 and $0.5 million in 2008.

Senior Notes Due 2020. These notes consist of $225 million of 8-7/8% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9-1/8%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the note. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on November 25, 2009. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. In addition, prior to January 15, 2013, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 108.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $20.5 million and $2.0 million for the years ended December 31, 2010 and 2009, respectively.

Senior Notes Due 2017. These notes consist of $250.0 million of 7-1/8% senior notes due 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. On or after June 1, 2012, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 2015 and thereafter. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $18.4 million for the year ended December 31, 2010 and $18.1 million for both years ended December 31, 2009 and 2008.

Senior Notes Due 2011. These notes consisted of $150.0 million of 7-5/8% senior subordinated notes due July 2011, which were issued on June 23, 2004 and which were fully redeemed as of December 10, 2009. In the fourth quarter of 2009, we recorded a charge of $4.0 million related to the redemption of these notes. The costs were comprised of approximately $2.9 million of premium paid to redeem the notes, and $1.1 million to write-off unamortized debt issuance costs.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $11.4 million in 2009 and $12.0 million in 2008.

The maturities on our long-term debt are $250.0 million in 2017 and $225.0 million in 2020.

5. Commitments and Contingencies

Rental and lease expenses which were included in “General and administrative, net” on our accompanying consolidated statements of operations were $5.4 million in 2010, $4.2 million in 2009, and $3.2 million in 2008. Rental and lease expenses which were included in “Lease operating cost” on our accompanying consolidated statements of operations were $10.5 million in both 2010 and 2009, and $8.6 million in 2008. Our remaining minimum annual obligations under non-cancelable operating lease commitments were $6.0 million for 2011, $5.8 million for 2012, $5.6 million for 2013, $5.6 million for 2014, $0.9 million for 2015 and $23.9 million in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas which is a ten year lease and expires in 2015. This lease is renewable for two five-year periods at the prevailing office rental rates in the area at the time of renewal.

In the ordinary course of business, we have entered into agreements for drilling and completion services. The remaining commitments at December 31, 2010 for these services and materials totaled $100.7 million.

60

Our remaining gas transportation minimum delivery obligations were $1.4 million for 2011, $1.9 million for 2012, $2.3 million for 2013, $2.6 million for 2014 and $8.2 million in the aggregate.

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders' Equity

Stock-Based Compensation Plans. We have three stock option plans that awards are currently granted under, the 2005 Stock Compensation Plan, which was adopted by our Board of Directors in March 2005 and was approved by shareholders at the 2005 annual meeting of shareholders, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants will be made under the 2001 Omnibus Stock Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the 2005 Stock Compensation Plan, although options remain outstanding under both plans and are accordingly included in the tables below. In addition, we have an employee stock purchase plan and an employee stock ownership plan.

Under the 2005 plan, stock options and other equity based awards may be granted to employees, directors, and consultants, with directors only eligible to receive restricted awards. Under the 2001 plan, stock options and other equity based awards may be granted to employees. Under the 1990 non-qualified plan, non-employee members of our Board of Directors were automatically granted options to purchase shares of common stock on a formula basis. All three plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested in various terms ranging from three years to five years, and stock options become exercisable in various terms ranging from one year to five years. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under these plans also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying statement of stockholders' equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary, within IRS limitations and plan rules, during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year. Under this plan for the last three years, we have issued 66,564 shares at a price of $14.29 in 2010, 50,690 shares at a price of $14.29 in 2009, and 25,645 shares at a price of $36.83 in 2008 and registered 200,000 new shares in 2008. As of December 31, 2010, 92,378 shares remained available for issuance under this plan.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. We receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. However, under this guidance, a tax benefit and a credit to additional paid-in capital for the excess deduction is not be recognized until that deduction reduces taxes payable. For the twelve months ended December 31, 2010, we incurred a tax benefit of $0.1 million as restricted stock vested at a slightly overall higher value than the value used to record compensation expense at the date of grant. Because the Company is in a cumulative tax loss carryover position for income taxes, this excess benefit was not recorded. For the twelve months ended December 31, 2009, we recognized a tax benefit shortfall of $2.0 million as restricted stock vested at a lower value than the value used to record compensation expense at the date of grant, offset by a reduction to additional paid-in capital. Additionally, during 2009 we derecognized excess tax benefits credited to additional paid-in capital in 2008 of $1.5 million. This derecognition was due to lower than estimated taxable income for the 2008 income tax return and utilization of a loss carry back to obtain a partial tax refund for taxes paid in 2007. After these adjustments, no actual cash benefit was realized for the excess tax benefits for vesting of restricted stock and exercise of stock options during 2008.

Net cash proceeds from the exercise of stock options were $2.1 million, $0.3 million, and $8.3 million for the years ended December 31, 2010, 2009, and 2008 respectively. The actual income tax benefit from stock option exercises was $0.8 million, $0.1 million, and $4.1 million for the same periods.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying consolidated statements of operations, and was $9.3 million, $8.4 million, and $10.6 million for the years ended December 31, 2010, 2009, and 2008, respectively. Stock compensation recorded in lease operating cost was $0.3 million, $0.4 million, and $0.6 million for the years ended December 31, 2010, 2009, and 2008, respectively. We also capitalized $1.6 million, $2.1 million, and $4.5 million of stock compensation in 2010, 2009, and 2008, respectively.

Our shares available for future grant under our stock compensation plans were 1,903,660 at December 31, 2010. Each stock option granted reduces the aforementioned total by one share, while each restricted stock grant reduces the shares available for future grant by 1.44 shares.

Stock Options. We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods:

	Years Ended December 31,		
	2010	2009	2008
Dividend yield	0 %	0 %	0 %
Expected volatility	62.8 %	50.5 %	39.5 %
Risk-free interest rate	2.1 %	1.8 %	2.4 %
Expected life of options (in years)	4.3	4.5	4.1
Weighted-average grant-date fair value	$ 12.60	$ 6.32	$ 15.26

The expected term for grants issued during or after 2008 has been based on an analysis of historical employee exercise behavior and considered all relevant factors including expected future employee exercise behavior. The expected term for grants issued prior to 2008 was calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility, and based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our 2010, 2009 and 2008 stock option grants.

At December 31, 2010, there was $1.5 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 0.8 year. The following table represents stock option activity for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Shares	Wtd Avg. Exer. Price	Shares	Wtd, Avg Exer. Price	Shares	Wtd. Avg Exer. Price
Options outstanding, beginning of period	1,289,194	$29.72	1,119,469	$33.22	1,449,240	$28.47
Options granted	273,463	$25.28	273,400	$14.66	216,315	$46.37
Options canceled	(36,983)	$44.65	(77,619)	$33.26	(44,289)	$34.69
Options exercised1	(163,895)	$18.11	(26,056)	$12.52	(501,797)	$24.96

Options outstanding, end of period	1,361,779	$29.67	1,289,194	$29.72	1,119,469	$33.22
Options exercisable, end of period	749,447	$32.04	790,394	$31.00	649,714	$26.41

1 The plans allow for the use of a "stock swap" in lieu of a cash exercise for options, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid "stock swap." Options issued under a "stock swap" also include a reload feature where additional options are granted at the then current market price when mature shares of Swift stock are used to satisfy the exercise price of an existing stock option grant. The terms of the plans provide that the mature shares delivered, as full or partial payment in a "stock swap", shall again be available for awards under the plans. In 2010 and 2008, 27,463 and 81,515 mature shares were delivered in "stock swap" transactions, respectively, which resulted in the issuance of an equal number of reload option grants. None were issued in 2009.

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at December 31, 2010 was $16.2 million and 5.6 years and $7.9 million and 3.7 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2010 was $2.6 million.

The following table summarizes information about stock options outstanding at December 31, 2010:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/10	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/10	Wtd. Avg. Exercise Price
$ 8.00 to $24.99	687,547	6.9	$18.27	259,278	$14.87
$25.00 to $44.99	567,161	4.9	$39.07	383,098	$37.77
$45.00 to $65.00	107,071	0.9	$53.11	107,071	$53.11
$ 8.00 to $65.00	1,361,779	5.6	$29.67	749,447	$32.04

Restricted Stock. In 2010, 2009 and 2008, the Company issued 388,650, 433,210 and 314,440 shares, respectively, of restricted stock to employees, consultants, and directors. These shares vest over a three-year to five-year period and remain subject to forfeiture if vesting conditions are not met. The fair value of these shares when issued was approximately $25 per share in 2010, $12 per share in 2009 and $44 per share in 2008.

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2010, we have unrecognized compensation expense of approximately $8.6 million associated with these awards which are expected to be recognized over a weighted-average period of 0.8 years. The total fair value of shares vested during the year ended December 31, 2010 was $9.0 million.

The following is a summary of our restricted stock issued to employees, consultants, and directors under these plans as of December 31, 2010, 2009, and 2008:

	2010		2009		2008	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg.Grant Price
Restricted shares outstanding, beginning of period	703,856	$24.15	586,325	$42.78	596,590	$41.60
Restricted shares granted	388,650	$25.41	433,210	$12.48	314,440	$43.61
Restricted shares canceled	(46,029)	$24.45	(51,750)	$41.86	(49,859)	$42.65
Restricted shares vested	(312,191)	$28.75	(263,929)	$42.92	(274,846)	$41.18
Restricted shares outstanding, end of period	734,286	$22.87	703,856	$24.15	586,325	$42.78

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan (“ESOP”) effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a three-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2010, 2009, and 2008, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2010, 2009 and 2008, and were all made in common stock, and are recorded as "General and administrative, net" on the accompanying consolidated statements of operations. The shares of common stock contributed to the ESOP plan totaled 5,108, 8,347 and 11,898 shares for the 2010, 2009, and 2008 contributions, respectively.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $1.3 million for both 2010 and 2009 and $1.5 million for 2008, and are recorded as "General and administrative, net" on the accompanying consolidated statements of operations. The contributions in 2010, 2009, and 2008 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 31,960, 50,988 and 82,125 shares for the 2010, 2009, and 2008 contributions, respectively.

Treasury Shares. In March 1997, our Board of Directors approved a common stock repurchase program that terminated as of June 30, 1999. Under this program, we spent approximately $13.3 million to acquire 927,774 shares in the open market at an average cost of $14.34 per share. At December 31, 2010, 441,525 shares remain in treasury (net of 726,015 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $9.8 million and are included in “Treasury stock held, at cost” on the accompanying consolidated balance sheets.

Shareholder Rights Plan. Our Rights Agreement was initially adopted by the Board of Directors in 1997 for a ten-year term. The Board of Directors renewed and extended the Rights Agreement for an additional ten-year term on December 21, 2006. Pursuant to the Rights Agreement as amended, for each share of Swift Energy common stock a holder has the right to purchase one one-thousandth of a share of Swift Energy preferred stock for $250 upon the occurrence of certain events triggered when a person or entity purchases 15% or more beneficial ownership of Swift Energy’s outstanding common stock. The rights are not exercisable by such 15% or more beneficial owner.

7. Related-Party Transactions

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the aunt of the Company’s Chairman of the Board and Chief Executive Officer. We paid approximately $0.6 million to Tec-Com for such services pursuant to the terms of the contract in both 2010 and 2009 and $0.7 million in 2008. The contract was renewed on July 1, 2010 on substantially the same terms as the previous contract and expires June 30, 2013. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee’s charter.

8. Discontinued Operations

In December 2007, we agreed to sell substantially all of our New Zealand assets. Accordingly, the New Zealand operations have been classified as discontinued operations in the consolidated statements of operations and cash flows and the assets and associated liabilities have been classified as held for sale in the consolidated balance sheets. In June 2008, we completed the sale of substantially all of our New Zealand assets for $82.7 million in cash after purchase price adjustments. Proceeds from this asset sale were used to pay down a portion of our credit facility. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments to be received nine months after the sale, 18 months after the sale, and 30 months after the sale. All payments under this sale agreement are secured by unconditional letters of credit, with the first two payments received in February 2009 and February 2010, respectively. Due to ongoing litigation, we have evaluated the situation and determined that certain revenue recognition criteria have not been met at this time for the permit sale, and have deferred the potential gain on this property sale pending further development of this litigation.

In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. Furthermore, the assets included as part of this divestiture have been reclassified as held for sale in the consolidated balance sheets.

The book value of our remaining New Zealand permit is approximately $0.6 million at December 31, 2010.

The following table summarizes the amounts included in “Loss from Discontinued Operations, net of taxes” for all periods presented. These revenues and expenses were historically reported under our New Zealand operating segment, and are now reported as discontinued operations (in thousands except per share amounts):

64

	2010	2009	2008
Oil and gas sales	$---	$---	$14,675
Other revenues	42	26	832
Total revenues	$42	$26	15,507
Depreciation, depletion, and amortization	---	---	4,857
Other operating expenses	223	280	10,750
Non-cash write-down of property and equipment	---	---	3,572
Total expenses	$223	$280	$19,179
Loss from discontinued operations before income taxes	(181)	(254)	(3,672)
Income tax benefit	---	---	312
Loss from discontinued operations, net of taxes	$(181)	$(254)	$(3,360)
Loss per share from discontinued operations-diluted	$(0.00)	$(0.01)	$(0.11)
Sales volumes (MBoe)	---	---	415
Cash flow provided by (used in) operating activities	$(41)	$(396)	$6,039
Capital expenditures	$---	$---	$1,273

Total income taxes differed from the amount computed by applying the statutory income tax rate to income from discontinued operations. The sources of these differences are as follows (in thousands):

	2010	2009	2008
Loss before tax from discontinued operations	$(180)	$(254)	$(3,672)
Income taxes computed at U.S. statutory rate (35%)	(63)	(89)	(1,285)
Effect of foreign operations	9	12	973
Currency exchange impact on foreign tax calculation	(1,917)	(6,377)	---
Valuation allowance	1,971	6,454	---
Total income tax expense related to discontinued operations	$0	$0	$(312)
Effective tax rate	0.0%	0.0%	8.5%

There were no significant net deferred assets (liabilities) associated with assets held for sale at December 31, 2010 and 2009.

In 2007 the Company reported a non-cash write-down of properties held for sale that resulted in an estimated net deferred tax asset balance of $33.5 million, calculated using the New Zealand tax rate of 30%. This estimated net asset was attributable to New Zealand tax loss carryovers that are denominated in New Zealand dollars. As of December 31, 2010, the U.S. dollar value of the deferred asset was $34.2 million. As of December 31, 2010, 2009 and 2008, management assessed that the probability of generating additional taxable income to utilize these loss carryovers was not more likely than not. Since the Company’s net book value of this deferred tax asset is zero, no adjustments have been made to the provision for income tax from discontinued operations for the change in the gross deferred tax asset value.

The following presents the main classes of assets and liabilities associated with the New Zealand operations that were held for sale as of December 31, 2010 and 2009 (in thousands):

	2010	2009
ASSETS		
Property and equipment, net	$ 564	$ 564
Total Current assets	$ 564	$ 564
LIABILITIES		
Deferred Revenue (1)	$ 10,000	$ 5,000
Total Current liabilities associated with assets held for sale	$ 10,000	$ 5,000

(1) Included in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheet.

9. Acquisitions and Dispositions

In November 2009, within our South Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Eagle Ford Shale in McMullen County, Texas. The Company leased a 50% working interest in approximately 26,000 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage and received approximately $26 million in cash consideration as well as consideration for approximately $13 million to fund future capital expenditures in the joint venture agreement, related to this transaction. As of December 31, 2010 we had approximately $0.2 million of the $13 million consideration remaining in our balance sheet. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

In August 2009, within our Central Louisiana/East Texas core area, we entered into a joint venture agreement with a large independent oil and gas producer active in the area for development and exploitation in and around the Burr Ferry field in Vernon Parish, Louisiana. The Company, as fee mineral owner, leased a 50% working interest in approximately 33,623 gross acres to the joint venture partner. Swift Energy retains a 50% working interest in the joint venture acreage as well as its fee mineral royalty rights, and received approximately $4.2 million related to this transaction. We used the proceeds from this joint venture to pay down a portion of the outstanding balance on our credit facility.

In August 2008, we announced the acquisition of oil and natural gas interests in South Texas from Crimson Energy Partners, L.P. a privately held company. The property interests are located in the Briscoe “A” lease in Dimmit County. Including an accrual of $0.6 million for purchase price adjustment reductions, we paid approximately $45.9 million in cash for these interests. After taking into account internal acquisition costs of $1.5 million, our total cost was $47.4 million. We allocated $44.0 million of the acquisition price to “Proved Properties,” $3.4 million to “Unproved Properties,” and recorded a liability for $0.2 million to “Asset retirement obligation” on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Texas. The revenues and expenses from these properties have been included in our accompanying consolidated statement of operations from the date of acquisition forward and due to the short time period held were not material to our 2008 results.

10. Fair Value Measurements

FASB ASC 820-10 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements. The adoption of this guidance did not have a material impact on our financial position or results of operations.

The following table presents our assets that are measured at fair value as of December 31, 2010 and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

Assets	Fair Value Measurements at December 31, 2010			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money Market Funds	$ 79.1	$ 79.1	$ ---	$ ---
Natural Gas Derivatives	$ 0.3	$ ---	$ 0.3	$ ---

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category include money market funds as they have comparable fair values for identical assets.

Level 2 – Uses quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets. Instruments in this category include our commodity derivatives that we value using commonly accepted industry-standard models (such as Black-Scholes) which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

Level 3 – Uses unobservable inputs for assets or liabilities that are in non-active markets. We do not have any assets or liabilities in this category that are not supported by market activity and have significant unobservable inputs.

11. Condensed Consolidating Financial Information

Swift Energy Company is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is a guarantor of our senior subordinated notes due 2017 and 2020. The guarantees on our senior subordinated notes due 2017 and 2020 are full and unconditional. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and other subsidiaries:

Condensed Consolidating Balance Sheets

(in thousands)	December 31, 2010				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$---	$160,794	$23	$---	$160,817
Property and equipment	---	1,572,845	---	---	1,572,845
	880,017	---	808,780	(1,688,797)	---

Investment in subsidiaries (equity method)					
Other assets	---	12,713	81,221	(81,221)	12,713
Total assets	$880,017	$1,746,352	$890,024	$(1,770,018)	$1,746,375
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	152,780	$10,007	$---	$162,787
Long-term liabilities	---	784,792	0	(81,221)	703,571
Stockholders' equity	880,017	808,780	880,017	(1,688,797)	880,017
Total liabilities and stockholders' equity	$880,017	$1,746,352	$890,024	$(1,770,018)	$1,746,375

(in thousands)	December 31, 2009				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$---	$102,975	$5,625	$---	$108,600
Property and equipment	---	1,315,964	---	---	1,315,964
Investment in subsidiaries (equity method)	678,899	---	602,483	(1,281,382)	---
Other assets	---	10,201	75,850	(75,850)	10,201
Total assets	$678,899	$1,429,140	$683,958	$(1,357,232)	$1,434,765
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$98,545	$5,059	$---	$103,604
Long-term liabilities	---	728,112	---	(75,850)	652,262
Stockholders' equity	678,899	602,483	678,899	(1,281,382)	678,899
Total liabilities and stockholders' equity	$678,899	$1,429,140	$683,958	$(1,357,232)	$1,434,765

Condensed Consolidating Statements of Operations

(in thousands)	Year Ended December 31, 2010				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 438,429	$ ---	$ ---	$ 438,429
Expenses	---	364,121	---	---	364,121
Income before the following:	---	74,308	---	---	74,308
Equity in net earnings of subsidiaries	46,294	---	46,475	(92,769)	---
Income from continuing operations, before income taxes	46,294	74,308	46,475	(92,769)	74,308
Income tax provision	---	27,833	---	---	27,833
Income from continuing operations	46,294	46,475	46,475	(92,769)	46,475
Loss from discontinued operations, net of taxes	---	---	(181)	---	(181)
Net Income	46,294	46,475	46,294	$ (92,769)	$ 46,294

(in thousands)	Year Ended December 31, 2009				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 370,445	$ ---	$ ---	$ 370,445
Expenses	---	435,062	---	---	435,062

Loss before the following:	---	(64,617)	---	---	(64,617)
Equity in net earnings of subsidiaries	(39,330)	---	(39,076)	78,406	---
Loss from continuing operations, before income taxes	(39,330)	(64,617)	(39,076)	78,406	(64,617)
Income tax benefit	---	(25,541)	---	---	(25,541)
Loss from continuing operations	(39,330)	(39,076)	(39,076)	78,406	(39,076)
Loss from discontinued operations, net of taxes	---	---	(254)	---	(254)
Net loss	$ (39,330)	$ (39,076)	$ (39,330)	$ 78,406	$ (39,330)

(in thousands)	Year Ended December 31, 2008				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ ---	$ 820,815	$ ---	$ ---	$ 820,815
Expenses	---	1,233,573	---	---	1,233,573
Loss before the following:	---	(412,758)	---	---	(412,758)
Equity in net earnings of subsidiaries	(260,490)	---	(257,130)	517,620	---
Loss from continuing operations, before income taxes	(260,490)	(412,758)	(257,130)	517,620	(412,758)
Income tax benefit	---	(155,628)	---	---	(155,628)
	(260,490)	(257,130)	(257,130)	517,620	(257,130)

Loss from continuing operations					
Loss from discontinued operations, net of taxes	---	---	(3,360)	---	(3,360)
Net loss	$ (260,490)	$ (257,130)	$ (260,490)	$ 517,620	$ (260,490)

68

Condensed Consolidating Statements of Cash Flow

(in thousands)	Year Ended December 31, 2010				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 258,996	$ (41)	$ ---	$ 258,955
Cash flow from investing activities	---	(348,515)	5,000	(5,000)	(348,515)
Cash flow from financing activities	---	137,458	(5,000)	5,000	137,458
Net increase in cash	---	47,939	(41)	---	47,898
Cash, beginning of period	---	38,407	62	---	38,469
Cash, end of period	$ ---	$ 86,346	$ 21	$ ---	$ 86,367

(in thousands)	Year Ended December 31, 2009				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 226,176	$ (396)	$ ---	$ 225,780
Cash flow from investing activities	---	(184,549)	5,000	262	(179,287)
Cash flow from financing activities	---	(8,307)	262	(262)	(8,307)
Net increase in cash	---	33,320	4,866	---	38,186
Cash, beginning of period	---	86	197	---	283
Cash, end of period	$ ---	$ 33,406	$ 5,063	$ ---	$ 38,469

(in thousands)	Year Ended December 31, 2008				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ ---	$ 582,027	$ 6,039	$ ---	$ 588,066
Cash flow from investing activities	---	(582,863)	80,504	(91,790)	(594,149)
Cash flow from financing activities	---	743	(91,790)	91,790	743
Net decrease in cash	---	(93)	(5,247)	---	(5,340)
Cash, beginning of period	---	180	5,443	---	5,623
Cash, end of period	$ ---	$ 87	$ 196	$ ---	$ 283

Supplementary Information

Swift Energy Company and Subsidiaries
Oil and Gas Operations (Unaudited)

Capitalized Costs. The following table presents our aggregate capitalized costs relating to oil and natural gas producing activities and the related depreciation, depletion, and amortization (in thousands):

	Total
December 31, 2010:	
Proved oil and gas properties	$ 3,835,173
Unproved oil and gas properties	78,429
	3,913,602
Accumulated depreciation, depletion, and amortization	(2,355,974)
Net capitalized costs	$ 1,557,628
December 31, 2009:	
Proved oil and gas properties	$ 3,421,340
Unproved oil and gas properties	71,640
	3,492,980
Accumulated depreciation, depletion, and amortization	(2,196,444)
Net capitalized costs	$ 1,296,536

Of the $78.4 million of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2010, excluded from the amortizable base, $28.7 million was incurred in 2010, $18.4 million was incurred in 2009, $8.1 million was incurred in 2008 and $23.2 million was incurred in prior years. We evaluate the majority of these unproved costs within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved oil and gas properties as of December 31, 2010, 2009, and 2008.

Costs Incurred. The following table sets forth costs incurred related to our oil and natural gas operations (in thousands):

	Year Ended December 31, 2010		
	Total	Domestic	Discontinued Operations
Lease acquisitions and prospect costs (1)	$ 60,641	$ 60,641	$ ---
Exploration	83,957	83,957	---
Development (2)	276,024	276,024	---
Total acquisition, exploration, and development (3), (4)	$ 420,622	$ 420,622	$ ---

	Year Ended December 31, 2009		
	Total	Domestic	Discontinued

			Operations
Lease acquisitions and prospect costs (1)	$ 61,105	$ 61,105	$ ---
Exploration	2,866	2,866	---
Development (2)	111,095	111,095	---
Total acquisition, exploration, and development (3), (4)	$ 175,066	$ 175,066	$ ---

	Year Ended December 31, 2008		
	Total	Domestic	Discontinued Operations
Acquisition of proved and unproved properties	$ 47,245	$ 47,245	$ --
Lease acquisitions and prospect costs (1)	72,513	71,240	1,273
Exploration	47,832	47,832	---
Development (2)	477,982	477,982	---
Total acquisition, exploration, and development (3), (4)	$ 645,572	$ 644,299	$ 1,273

(1) These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2010, 2009, and 2008 were $50.3 million, $56.8 million, and $56.7 million, respectively. Domestic costs for seismic data acquisition, included above, were $6.1 million, 4.4 million, and $12.4 million in 2010, 2009, and 2008, respectively.

(2) Facility construction costs and capital costs have been included in development costs, and totaled $29.9 million, $18.4 million, and $48.2 million for the years ended December 31, 2010, 2009, and 2008, respectively.

(3) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $24.6 million, $24.5 million, and $30.1 million in 2010, 2009, and 2008, respectively. In addition, the total includes $7.4 million, $6.1 million, and $8.0 million in 2010, 2009, and 2008, respectively, of capitalized interest on unproved properties.

(4) Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2010, 2009, and 2008.

Results of Operations (in thousands).

	Year Ended December 31, 2010		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 436,632	$ 436,632	$ ---
Lease operating cost	(81,929)	(81,929)	---
Severance and other taxes	(45,868)	(45,868)	---
Depreciation, depletion, and amortization	(159,532)	(159,532)	---
Accretion of asset retirement obligation	(3,956)	(3,956)	---
	145,347	145,347	---
(Provision) Benefit for income taxes	(54,505)	(54,505)	---
Results of producing activities	$ 90,842	$ 90,842	$ ---
Amortization per physical unit of production (equivalent Bbl of oil)	$ 19.15	$ 19.15	$ ---

	Year Ended December 31, 2009		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 371,749	$ 371,749	$ ---
Lease operating cost	(76,744)	(76,740)	(4)
Severance and other taxes	(41,326)	(41,326)	---
Depreciation, depletion, and amortization	(162,908)	(162,908)	---
Accretion of asset retirement obligation	(2,906)	(2,906)	---
Write-down of oil and gas properties	(79,312)	(79,312)	---
	8,553	8,557	(4)
(Provision) Benefit for income taxes	(3,378)	(3,378)	---
Results of producing activities	$ 5,175	5,179	$ (4)
	$ 17.99	$ 17.99	$ ---

Amortization per physical unit of production
(equivalent Bbl of oil)

	Year Ended December 31, 2008		
	Total	Domestic	Discontinued Operations
Oil and gas sales	$ 808,534	$ 793,859	$ 14,675
Lease operating cost	(111,220)	(104,874)	(6,346)
Severance and other taxes	(81,376)	(80,403)	(973)
Depreciation, depletion, and amortization	(224,201)	(219,344)	(4,857)
Accretion of asset retirement obligation	(2,019)	(1,958)	(61)
Write-down of oil and gas properties	(757,870)	(754,298)	(3,572)
	(368,152)	(367,018)	(1,134)
(Provision) Benefit for income taxes	138,444	138,366	78
Results of producing activities	$ (229,708)	$ (228,652)	$ (1,056)
Amortization per physical unit of production (equivalent Bbl of oil)	$ 21.43	$ 21.83	$ 11.71

These results of operations do not include the gains (losses) from our hedging activities of $0.7 million, ($1.4) million and $26.1 million for 2010, 2009 and 2008, respectively. Our lease operating costs per Boe produced were $9.84 in 2010, $8.47 in 2009 and $10.44 in 2008.

We used our effective tax rate in each country to compute the provision (benefit) for income taxes in each year presented.

Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were determined by us, and our domestic reserves were audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 98% of our 2010 domestic proved reserves, 96% of our 2009 domestic proved reserves and 97% of our domestic proved reserves for 2008. The audit by Gruy conformed to the meaning of the term "reserves audit" as presented in Regulation S-K, Item 1202. Gruy's audit was based upon review of production histories and other geological, economic, and engineering data provided by us. Gruy's report dated February 18, 2011, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2010, and includes assumptions and references to the definitions that serve as the basis for the audit of proved reserves and future net cash flows.

Estimates of Proved Reserves			Domestic			Discontinued Operations	
	Total (Boe)	Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
Proved reserves as of December 31, 2007	150,123,822	343,798,112	58,316,594	18,165,017	50,216,024	6,273,608	1,699,580
Revisions of previous estimates(1)	(13,990,865)	(42,734,480)	(7,001,433)	132,981	---	---	---
Purchases of minerals in place	991,195	3,193,519	37,030	421,912	---	---	---
Sales of minerals in place	(15,927,578)	---	---	---	(48,382,504)	(6,216,101)	(1,647,726)
Extensions, discoveries, and other additions	5,707,582	8,626,050	3,752,968	516,939	---	---	---
Production	(10,463,698)	(20,503,244)	(5,420,242)	(1,211,301)	(1,833,520)	(57,507)	(51,854)
Proved reserves as of December 31, 2008	116,440,458	292,379,957	49,684,917	18,025,548	---	---	---
Revisions of previous estimates(1)	(3,005,184)	(13,544,236)	(1,237,388)	489,577	---	---	---
Purchases of minerals in place	---	---	---	---	---	---	---
	---	---	---	---	---	---	---

Sales of minerals in place							
Extensions, discoveries, and other additions	8,548,395	32,874,203	389,221	2,680,140	---	---	---
Production	(9,055,226)	(21,157,002)	(4,346,370)	(1,182,689)	---	---	---
Proved reserves as of December 31, 2009	112,928,443	290,552,922	44,490,380	20,012,576	---	---	---
Revisions of previous estimates(1)	(8,487,441)	5,898,299	(9,085,180)	(385,310)	---	---	---
Purchases of minerals in place	---	---	---	---	---	---	---
Sales of minerals in place	---	---	---	---	---	---	---
Extensions, discoveries, and other additions	36,670,870	146,251,737	7,836,861	4,458,719	---	---	---
Production	(8,329,522)	(19,721,167)	(3,905,003)	(1,137,658)	---	---	---
Proved reserves as of December 31, 2010	132,782,350	422,981,791	39,337,058	22,948,327	---	---	---
Proved developed reserves:(2)							
December 31, 2007	67,944,579	172,973,952	25,848,914	9,698,668	14,178,356	806,438	398,508
December 31, 2008	62,113,506	172,214,540	22,710,392	10,700,691	---	---	---
December 31, 2009	56,797,353	155,404,822	19,659,802	11,236,747	---	---	---
December 31, 2010	60,398,306	190,454,346	16,781,587	11,874,328	---	---	---

(1) Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2010 and 2009 were based upon the preceding 12-months' average price based on closing prices on the first business day of each month, or prices defined by existing contractual arrangements are held constant, for that year's reserves calculation. Our hedges at year-end 2010 and 2009 did not materially affect prices used in these

calculations. The 12-month average 2010 prices used in our calculations for domestic operations were $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL compared to $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL for the 12-month average 2009 prices. The year-end 2008 prices used for domestic operations were $6.65 per Mcf of natural gas, $93.24 per barrel of oil, and $56.28 per barrel of NGL for domestic operations.

(2) At December 31, 2010, 45% of our domestic reserves were proved developed, compared to 50% at December 31, 2009, and 53% at December 31, 2008.

Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Future gross revenues	$5,768,030	$4,358,412	$4,099,878
Future production costs	(1,384,275)	(1,289,556)	(1,115,986)
Future development costs	(1,441,901)	(1,034,443)	(933,197)
Future net cash flows before income taxes	2,941,854	2,034,413	2,050,694
Future income taxes	(746,845)	(478,876)	(454,675)
Future net cash flows after income taxes	2,195,009	1,555,537	1,596,019
Discount at 10% per annum	(850,301)	(535,080)	(563,015)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$1,344,708	$1,020,457	$1,033,004

The standardized measure of discounted future net cash flows from production of proved reserves at year-end 2010 was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.
2. The estimated future gross revenues of proved reserves are based on the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements.
3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as asset retirement obligation costs, net of salvage value, based on year-end cost estimates and the estimated effect of future income taxes.
4. Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future oil and natural gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. Our hedges at year-end 2010 consisted of natural gas price floors that did not have a material effect on prices used in these calculations. Subsequent changes to such oil and natural gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the consolidated financial statements). Application of these rules during periods of relatively low oil and natural gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of our oil and natural gas property reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment, and the risks inherent in reserves estimates.

The standardized measure of discounted future net cash flows for 2008 was computed using rules in effect for that period.

The following are the principal sources of change in the standardized measure of discounted future net cash flows (in thousands):

	Year Ended December 31, 2010	2009	2008
Beginning balance	$1,020,457	$1,033,004	$2,636,443
Revisions to reserves proved in prior years--			
Net changes in prices, net of production costs	501,997	149,000	(2,020,645)
Net changes in future development costs	(47,935)	(51,501)	(36,286)
Net changes due to revisions in quantity estimates	(186,180)	(53,094)	(229,290)
Accretion of discount	132,231	131,313	384,847
Other	(80,393)	(17,335)	(321,458)
Total revisions	319,720	158,383	(2,222,831)
New field discoveries and extensions, net of future production and development costs	325,561	40,447	91,414
Purchases of minerals in place	---	---	12,160
Sales of minerals in place	---	---	(90,148)
Sales of oil and gas produced, net of production costs	(308,834)	(253,683)	(616,272)
Previously estimated development costs incurred	118,147	64,033	290,337
Net change in income taxes	(130,343)	(21,727)	931,901
Net change in standardized measure of discounted future net cash flows	324,251	(12,547)	(1,603,439)
Ending balance	$1,344,708	$1,020,457	$1,033,004

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2010 and 2009 (in thousands, except per share data):

	Revenues	Income (Loss) from Continuing Operations Before Taxes	Income (Loss) from Continuing Operations	Loss from Discontinued Operations	Basic EPS from Continuing Operations	Diluted EPS from Continuing Operations
2010:						
First	$109,846	$22,821	$14,240	$ (35)	$0.37	$0.37
Second	106,900	19,068	12,513	(54)	0.32	0.32
Third	105,646	15,055	9,403	(73)	0.24	0.24
Fourth	116,037	17,364	10,319	(19)	0.25	0.25
Total	$438,429	$74,308	46,475	$ (181)	$1.19	$1.18
2009:						
First	$76,359	$(91,969)	$(59,003)	$ (126)	$(1.90)	$(1.90)
Second	82,921	(2,281)	(2,210)	(57)	(0.07)	(0.07)
Third	96,263	8,144	7,558	(32)	0.21	0.21
Fourth	114,902	21,489	14,579	(39)	0.38	0.38

Total	$370,445	$(64,617)	$(39,076)	$ (254)	$(1.16)	$(1.16)

There were no extraordinary items in 2010 or 2009. Our New Zealand operations are accounted for as discontinued operations. In the first quarter of 2009, as a result of low oil and natural gas prices at March 31, 2009, we reported a non-cash write-down on a before-tax basis of $79.3 million ($50.0 million after tax) on our oil and natural gas properties.

The sum of the individual quarterly net income (loss) per common share amounts may not agree with year-to-date net income (loss) per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted net income (loss) per common share because to do so would have been antidilutive.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K and have determined that such disclosure controls and procedures are effective.

There was no change in our internal control over financial reporting during the quarter ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report On Internal Control Over Financial Reporting as of December 31, 2010 is included in Item 8. Financial Statements and Supplementary Data. The Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting is also included in Item 8.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 10, 2011, annual shareholders' meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 10, 2011, annual shareholders' meeting is incorporated herein by reference.

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

The information required under Item 12 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 10, 2011, annual shareholders' meeting is incorporated herein by reference.

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

The information required under Item 13 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 10, 2011, annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 10, 2011, annual shareholders' meeting is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 23, 2011, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

3. Exhibits

3.1	Certificate of Formation of Swift Energy Company (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 filed November 3, 2009, File No. 1-08754).
3.2	Second Amended and Restated Bylaws of Swift Energy Company, effective October 30, 2009 (incorporated by reference as Exhibit 3.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 filed November 3, 2009, File No. 1-08754).
3.3	Certificate of Designation of Series A Junior Participating Preferred Stock of Swift Energy Company (incorporated by reference as Exhibit 3.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.1	Indenture dated as of May 19, 2009, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form S-3 filed May 19, 2009, and amended June 17 and June 26, 2009, File No. 1-08754).
4.2	First Supplemental Indenture dated as of November 25, 2009, between Swift Energy Company, Swift Energy Operating, LLC, and Wells Fargo Bank, National Association, as Trustee, including the form of 8 7/8% Senior Notes (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 2, 2009, File No. 1-08754).

4.3	Amended and Restated Rights Agreement between Swift Energy Company and American Stock Transfer & Trust Company, dated March 31, 1999 (incorporated by reference to Swift Energy Company's Amendment No. 1 to Form 8-A filed April 7, 1999, File No. 1-08754).

4.4	Amendment No. 1 to the Rights Agreement dated December 12, 2005 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.3 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.5	Assignment, Assumption, Amendment and Novation Agreement between Swift Energy Company, New Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent effective at 9:00 a.m. local time in Austin, Texas on December 28, 2005 (incorporated by reference as Exhibit 4.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.6	Amendment No. 2 to the Rights Agreement dated December 21, 2006 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 22, 2006, File No. 1-08754).
4.7	Form of indenture dated as of May 16, 2007 between Swift Energy Company and Wells Fargo Bank, National Association (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Registration Statement on Form S-3 filed May 17, 2007, File No. 333-143034).
4.8	First Supplemental Indenture dated as of June 1, 2007, between Swift Energy Company, Swift Energy Operating, LLC and Wells Fargo Bank, National Association relating to the 7-1/8% Senior Notes due 2017 (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed June 7, 2007, File No. 1-08754).
10.1+	Amended and Restated Swift Energy Company 1990 Nonqualified Stock Option Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company's definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.2+	Amendment to the Swift Energy Company 1990 Stock Compensation Plan, as of May 9, 2000 (incorporated by reference as Exhibit 4.2 to the Swift Energy Company registration statement No. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.3+	Swift Energy Company 2001 Omnibus Stock Compensation Plan, as of January 1, 2001 (incorporated by reference as Exhibit 4.3 to the Swift Energy Company registration statement no. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.4	Form of Indemnity Agreement for Swift Energy Company officers (incorporated by reference as Exhibit 10.9 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006

	filed February 28, 2007, File No. 1-08754).
10.5	Form of Indemnity Agreement for Swift Energy Company directors (incorporated by reference as Exhibit 10.10 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-08754).
10.6+	Consulting Agreement between Swift Energy Company and Virgil N. Swift effective as of July 1, 2006 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006 filed May 5, 2006, File No. 1-08754).
10.7+	Forms of agreements for grant of incentive stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.19 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005 filed March 1, 2006, File No. 1-08754).

10.8	Second Amended and Restated Credit Agreement effective as of September 21, 2010, among Swift Energy Company, Swift Energy Operating, LLC and JPMorgan Chase Bank, N.A. as Administrative Agent, BNP Paribas and Wells Fargo Bank, N.A. as Co-Syndication Agents, Bank of Scotland PLC and Societe Generale, as Co-Documentation Agents, and the Lenders party thereto (incorporated by reference as Exhibit 10.01 to the Swift Energy Company's Form 8-K filed September 27, 2010, File No. 1-08754).
10.9	Eighth Amendment to Lease Agreement between Swift Energy Company and Greenspoint Plaza Limited Partnership dated as of June 30, 2004 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004 filed August 6, 2004, File No. 1-08754).
10.10+	Amendment No. 1 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed April 1, 2009, File No. 1-08745).
10.11+	Amendment No. 2 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Form 8-K filed May 14, 2009, File No. 1-08754).
10.12+	Amendment No. 3 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 12, 2010, File No. 1-08754).
10.13	Asset Purchase and Sale Agreement between Escondido Resources LP and Swift Energy Operating, LLC dated as of September 4, 2007 but effective as of July 1, 2007 (incorporated by reference as Exhibit 99.1 to the Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2007 filed November 1, 2007).
10.14	Agreement for Sale and Purchase of Assets between Swift Energy New Zealand Limited, Swift Energy New Zealand Holdings Limited, Southern Petroleum (New Zealand) Exploration Limited, Origin Energy Recourses NZ (SPV1) Limited, Origin Energy Resources NZ (SPV2) Limited and Origin Energy Limited effective December 1, 2007 (incorporated by reference as Exhibit 10.35 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2007, File No. 1-08754).
10.15+	First Amended and Restated 2005 Stock Compensation Plan dated November 4, 2008 (incorporated by reference as Exhibit 10.1 to Swift

Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.16+	Swift Energy Company Change of Control Severance Plan dated November 4, 2008 (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.17+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift dated November 4, 2008 (incorporated by reference as Exhibit 10.3 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.18+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Bruce H. Vincent dated November 4, 2008 (incorporated by reference as Exhibit 10.4 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.19+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Alton D. Heckaman dated November 4, 2008 (incorporated by reference as Exhibit 10.5 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.20+	Executive Employment Agreement between Swift Energy Company and Robert J. Banks dated November 4, 2008 (incorporated by reference as Exhibit 10.6 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.21+	Amended and Restated Executive Employment Agreement between Swift Energy Company and James P. Mitchell dated November 4, 2008 (incorporated by reference as Exhibit 10.8 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).

10.22+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and James M. Kitterman dated November 4, 2008 (incorporated by reference as Exhibit 10.7 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.23+	Employee Stock Purchase Plan, Generally Amended and Restated as of January 1, 2009.
12 *	Swift Energy Company Ratio of Earnings to Fixed Charges.
21 *	List of Subsidiaries of Swift Energy Company.
23.1 *	Consent of H.J. Gruy and Associates, Inc.
23.2 *	Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31.1 *	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32 *	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	The summary of H.J. Gruy and Associates, Inc. reported February 18, 2011.

* Filed herewith.
\+ Management contract or compensatory plan or arrangement.

SIGNATURES

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

SWIFT ENERGY COMPANY

By:
/s/ Terry E. Swift
Terry E. Swift
Chairman of the Board

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, Swift Energy Company, and in the capacities and on the dates indicated:

Signatures	Title	Date
/s/ Terry E. Swift Terry E. Swift	Director Chief Executive Officer	February 24, 2011
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 24, 2011
/s/ Barry S. Turcotte Barry S. Turcotte	Vice-President Controller Principal Accounting Officer	February 24, 2011
/s/ Deanna L. Cannon Deanna L. Cannon	Director	February 23, 2011

/s/ Douglas J. Lanier Douglas J. Lanier	Director	February 23, 2011
/s/Greg Matiuk Greg Matiuk	Director	February 23, 2011
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	February 23, 2011
/s/ Charles J. Swindells Charles J. Swindells	Director	February 23, 2011
/s/ Bruce H. Vincent Bruce H. Vincent	Director	February 24, 2011