SWIFT ENERGY CO
Form 10-K
February 23, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2011

Commission File Number 1-8754

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

TEXAS (State of Incorporation)	20-3940661 (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.
Yesþ No

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. o

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

1

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, 2011, the last business day of June 2011, was approximately $1,549,132,358.

The number of shares of common stock outstanding as of January 31, 2012 was 42,540,699.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 8, 2012	Part III, Items 10, 11, 12, 13 and 14

2

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 8, 2012

PART I

Items 1 and 2. Business and Properties

See pages 28 and 29 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 2011, we had estimated proved reserves from our continuing operations of 159.6 MMBoe with a PV-10 of $1.9 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 2011 were approximately 20% crude oil, 64% natural gas, and 16% NGLs; and 35% of our total proved reserves were developed. Our proved reserves are concentrated with 79% in Texas and 21% in Louisiana.

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

- South Texas

- Olmos

AWP
Sun TSH

- Eagle Ford

AWP
Artesia Wells
Fasken

- Southeast Louisiana

Lake Washington
Bay de Chene

- Central Louisiana/East Texas

Brookeland
South Bearhead Creek
Masters Creek
Burr Ferry

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 118.4 MMBoe to 159.6 MMBoe over the five-year period ended December 31, 2011. Over the same period, our annual production has grown from 9.4 MMBoe to 10.5 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our core areas.

During 2011, our proved reserves increased by 20%, 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 185% of our production on average over the last five years with our new reserves.

We currently plan to balance our 2012 capital expenditures with our 2012 cash flow, cash on hand and potential line of credit borrowings. Our 2012 planned capital expenditures are $575 to $625 million with 75% to 80% focused on our continued development in the liquids rich acreage in the Eagle Ford shale and the Olmos sands in our South Texas area. The Company may also explore joint venture arrangements for particular prospects to accelerate drilling and development of its assets and diversify its risk profile. For 2012, we are targeting an increase in production volumes of 14% to 20% over 2011 levels and proved reserves growth of 10% to 15% over 2011 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 $9.95, $9.84 and $8.47 per Boe in 2011, 2010, and 2009, 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 96% of our proved oil and natural gas reserves base as of December 31, 2011. 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 Texas 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 2011 even though we have been producing from this formation for over 20 years. The Company has acquired 800 square miles of 3D seismic data over the AWP and Artesia Wells areas. In 2011 we merged and prestack time migrated 700 square miles of this data into a continuous volume that we are using to plan our wells and enhance and expand our developments at AWP. In late

2011 we initiated a project to merge and prestack time migrate an additional 100 square miles of data in the Artesia Wells area.

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 approximately 48 MMBoe and still have remaining proved reserves of 14.4 MMBoe.

In October 2007, we acquired interests in two South Texas properties in the Gulf Coast basin (Sun TSH and Fasken) 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 Fasken 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, 2011, our debt to capitalization was approximately 42%, while our debt to proved reserves ratio was $4.51 per Boe, and our debt to PV-10 ratio was 36%. 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 79 oil and gas technical professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for an average of approximately five 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 2011, we completed 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 were processed and merged with other available seismic data, and integrated with geologic data, we developed proprietary geo-science databases that we use to guide our exploration and development programs.

The application of horizontal drilling and multi-stage hydraulic fracturing technology has resulted in increases in production and decreases in completion and operating costs, particularly in our South Texas Olmos and Eagle Ford operations. In 2011, we successfully drilled 38 horizontal wells in our South Texas area using this technology. We will continue to improve and employ this new technology in South Texas and apply this to other areas in which we operate. We use numerous recovery techniques, including gas lift, acid treatments, water flooding, and pressure maintenance to enhance crude oil and natural gas production in all of our core operating areas. 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.

Swift Energy’s success at drilling both in South Texas and in Louisiana can be marked by requiring excellence in geosciences and engineering. This is accomplished by elevating the quality of engineering first and operations second, with a focus on continuing improvement. Specific drilling and completion 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 operations. Lastly, the quality of the equipment and field personnel, together with a complete drilling process, is consistently enforced. This is the 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 2011 year-end proved reserves from continuing operations of 159.6 MMBoe and production of 10.5 MMBoe by area:

Core Area	Developed Reserves (MMBoe)	Undeveloped Reserves (MMBoe)	Total Proved Reserves (MMBoe)	% of Total Reserves	Oil and NGLs as % of Reserves	% of Total Production	Oil and NGLs as % of Production
AWP - Olmos	20.6	21.3	41.9	26.3 %	35.1 %	26.7 %	36.2 %
AWP – Eagle Ford	5.6	29.2	34.8	21.8 %	27.0 %	10.5 %	51.7 %
Fasken – Eagle Ford	6.7	27.2	33.9	21.3 %	0.0 %	13.6 %	0.0 %
Other South Texas	8.1	5.1	13.2	8.2 %	43.3 %	5.6 %	46.4 %
Total South Texas	41.0	82.8	123.8	77.6 %		56.4 %	
Southeast Louisiana	8.9	8.4	17.3	10.8 %	84.8 %	30.1 %	80.4 %
Central Louisiana / East Texas	5.7	12.7	18.4	11.5 %	66.5 %	13.1 %	58.7 %
Other	0.1	---	0.1	0.1 %	1.0 %	0.4 %	31.9 %
Total	55.7	103.9	159.6	100 %	35.6 %	100 %	49.7 %

Focus Areas

Our operations are primarily focused in three core areas identified as Southeast Louisiana, South Texas, and Central Louisiana/East Texas. 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 Fasken area 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 area was established when we acquired majority interests in producing properties in the Lake Washington field in early 2001 and in the Bay de Chene field in December 2004.

South Texas

AWP - Eagle Ford. In 2009 the Company initiated an active exploration and development program in the AWP Eagle Ford formation. During 2011 the Company drilled 17 wells in our AWP Eagle Ford field, including six non-operated joint venture wells. 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.

Based on the results of wells drilled in 2011 we have identified 81 proved undeveloped locations. During 2012 we plan to drill approximately 12 wells targeting the AWP Eagle Ford field. Our December 31, 2011 proved reserves in this formation are 73% natural gas, 10% oil, and 17% NGLs on a Boe basis.

AWP - Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled 12 horizontal Olmos wells in 2011. These wells were all operated and 100% owned by Swift Energy. We operate 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 65% natural gas, 27% NGLs, and 8% oil on a Boe basis.

At year-end 2011, we had 41 proved undeveloped locations in the Olmos. Our planned 2012 capital expenditures will include drilling approximately 14 horizontal wells targeting the Olmos formation, and we plan to perform approximately 15 production enhancement projects including fracture stimulations, pumping unit installations and installation of additional compression.

Fasken – Eagle Ford. During 2011 the Company drilled six operated wells in the Fasken Eagle Ford area. Based on the results of wells drilled in 2011 we have identified 41 proved undeveloped locations. During 2012 we plan to drill approximately two wells targeting the Fasken Eagle Ford area. Our December 31, 2011 proved reserves in this formation are 100% natural gas.

Artesia – Eagle Ford. During 2011 the Company drilled three operated wells in the Artesia Wells area. Based on the results of wells drilled in 2011 we have identified 10 proved undeveloped locations. During 2012 we plan to drill approximately 17 wells targeting the Artesia Eagle Ford area.

South Texas Acreage. As of December 31, 2011, we owned drilling and production rights to 79,308 net acres overlaying the Eagle Ford, of which 62,862 are undeveloped. We also owned drilling and production rights in 102,770 net acres overlying the Olmos (much of which also overlaps the Eagle Ford) in South Texas, of which 55,898 is undeveloped.

Southeast Louisiana

Lake Washington. As of December 31, 2011, we owned drilling and production rights in 14,722 net acres in the Lake Washington field located in Southeast Louisiana near shore 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 92% of our proved reserves of 14.4 MMBoe in this field as of December 31, 2011, consisted of oil and NGLs. Oil and natural gas 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 2011 we drilled two development wells. These two wells will yield between seven to 11 prospects in the future. In our production optimization program we performed 24 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At year-end 2011, we had 53 proved undeveloped locations in this field. Our planned 2012 capital expenditures in the field will include drilling up to 10 wells and performing recompletions on approximately 15 wells.

Bay de Chene. The Bay de Chene field is located along the border of Jefferson Parish and Lafourche Parish in near shore waters approximately 25 miles from the Lake Washington field. As of December 31, 2011, we owned drilling and production rights in approximately 14,653 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. During 2011 we did not drill any wells in the Bay De Chene field. At year-end 2011, we had two proved undeveloped locations in the Bay de Chene field. During 2012, we plan to drill one well in Bay de Chene.

Central Louisiana/East Texas

Burr Ferry. The Company has 73,679 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 also owns fee mineral interest in approximately 29,000 unleased acres, primarily in our Burr Ferry field. During 2011 the Company drilled one non-operated well in this joint venture. The Company also drilled one operated well in this field, separate from the joint venture. The reserves are approximately 65% oil and NGLs. We have identified 10 additional proved undeveloped locations in this field. In 2012, we plan to drill between four to six wells and perform production enhancements on approximately two wells.

Masters Creek. As of December 31, 2011, we owned drilling and production rights in 37,685 net acres in the Masters Creek field. The Masters Creek field is located in Vernon Parish and Rapides Parish, Louisiana. Oil and natural gas wells are produced from the Austin Chalk formation within natural fractures encountered in the lateral borehole sections from depths of 11,500 to 13,500 feet. The reserves are approximately 71% oil and NGLs. At year-end 2011, we had seven proved undeveloped locations. During 2011 we drilled one operated well in this field.

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, 2011, we owned drilling and production rights in 6,226 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 2011, we did not drill any wells in this field. At year-end 2011 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, 2011, we owned drilling and production rights in 68,270 net acres in this field. 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 NGLs. During 2011 we drilled one non-operated well in this field.

Disposition. In October 2011, we sold our interests in six fields in South Louisiana, two in Texas and one in Alabama. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field includes Chunchula. We also retained deep mineral rights for certain fields included in this disposition.

Other

Four Corners. At the end of 2011, we had approximately 31,577 net acres leased in the Four Corners area of southwest Colorado. In 2012, we plan to drill up to three wells in this area.

New Zealand Areas (Discontinued Operations)

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. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result in the second quarter of 2011, the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. 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. As of December 31, 2011, all payments under this sale agreement had been received and 100% of the Company’s oil and gas operations resided in the United States of America.

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, 2011, 2010, and 2009. The information set forth in the tables regarding reserves is based on proved reserves reports we have prepared. Our Director of Reserves and 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 94% of our 2011 domestic proved reserves, 98% of our domestic proved reserves for 2010 and 96% of our domestic proved reserves for 2009. 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. 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, 2011,2010, and 2009 are made based on the preceding 12-months' average adjusted price after differentials 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. 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 2011 average adjusted prices after differentials for domestic operations were $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL, compared to $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL at year-end 2010 and $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL at year-end 2009.

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, 2011, 2010, and 2009. 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,		
	2011	2010	2009
Estimated Proved Oil, NGL and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	184,355	190,454	155,405
Proved undeveloped	432,404	232,528	135,148
Total	616,759	422,982	290,553
Oil reserves (MBbl):			
Proved developed	13,840	16,782	19,659
Proved undeveloped	17,091	22,555	24,831
Total	30,931	39,337	44,490
NGL reserves (MBbl):			
Proved developed	11,078	11,874	11,237
Proved undeveloped	14,759	11,074	8,776
Total	25,837	22,948	20,012

Total Estimated Reserves (MBoe)	159,562	132,782	112,928
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$1,145	$974	$766
Proved undeveloped	773	803	557
PV-10 Value	$1,918	$1,777	$1,323

The PV-10 values for 2011, 2010, and 2009 are net of $75.0 million, $82.3 million, and $64.2 million of asset retirement obligation liabilities, respectively.

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reserves estimation 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,		
	2011	2010	2009
(in millions)			
PV-10 Value	$ 1,918	$ 1,777	$ 1,323
Future income taxes (discounted at 10%)	(400)	(432)	(302)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$ 1,518	$ 1,345	$ 1,021

Domestic Proved Undeveloped Reserves

The following table sets forth the aging of our domestic proved undeveloped reserves as of December 31, 2011:

Year Added	Volume (MMBoe)	% of PUD Volumes
2011	55.8	54 %
2010	33.8	32 %
2009	5.0	5 %
2008	3.3	3 %
2007	2.2	2 %
2006	3.8	4 %
Total	103.9	100 %

During 2011, we recorded 53.4 MMBoe of additional proved undeveloped reserves based on the results of the drilling program conducted during the year in the South Texas area. We also spent approximately $244 million in capital expenditures during the year to convert proved undeveloped reserves to proved developed reserves in our South Texas fields, resulting in the conversion of 12.3 MMBoe to proved developed reserves, which represents 17% of the prior year-end proved undeveloped reserves. Proved undeveloped reserves also decreased by approximately 8.6 MMBoe due to the sale of certain properties located in Louisiana, Texas and Alabama in October of 2011 as discussed in footnote 9 to our consolidated financials.

The PV-10 value from our proved undeveloped reserves was $0.8 billion at December 31, 2011 which was approximately 40% of our total PV-10 value of $1.9 billion. The PV-10 of our proved undeveloped reserves, by year of booking, are 4% in 2011, 49% in 2010, 2% in 2009, 15% in 2008, 12% in 2007 and 18% in 2006.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2011, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 159.6 MMBoe by approximately 0.3 MMBoe, and would increase the PV-10 Value of $1.9 billion by approximately $123 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.3 MMBoe and would decrease the PV-10 Value by approximately $122 million.

As of December 31, 2011 a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.2 MMBoe and would increase the PV-10 Value by approximately $64 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 $64 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, 2011:			
Gross	342	729	1,071
Net	316.5	699.2	1,015.7
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

(1) Excludes 38 service wells in 2011, 58 service wells in 2010 and 59 service wells in 2009.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2011:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	---	---	55,957	31,577
Louisiana (1)	107,943	91,625	117,077	69,593
Texas (2)	155,107	119,572	60,191	54,649
Wyoming	640	151	6,651	4,664
Total	263,690	211,348	239,876	160,483

(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 13,469 gross and 10,889 net developed acres and 46,365 gross and 41,595 net undeveloped acres. The Company also owns fee mineral interest in approximately 29,000 acres that are 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. Acreage which is developed in any formation is counted in the developed acreage above, even though there may also be undeveloped acreage in other formations. In the Eagle Ford, we have 18,366 gross and 16,446 net developed acres and 77,474 gross and 62,862 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos we have 47,611 gross and 47,872 net developed acres and 59,189 gross and 55,898 net undeveloped acres.

As of December 31, 2011, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 28% in 2012, 32% in 2013 and 2% in 2014. 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, 2011:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2011	Exploratory	---	---	---	---	---	---
	Development	44	44	---	39.6	39.6	---
2010	Exploratory	11	10	1	9.5	8.5	1.0
	Development	45	38	7	41.9	34.9	7.0
2009	Exploratory	2	1	1	2.0	1.0	1.0
	Development	18	17	1	18.0	17.0	1.0

Present Activities

As of December 31, 2011 we were in the process of drilling four wells in which we own a 100% working interest. We have also continued the production optimization program in the Lake Washington field to mitigate natural field declines, involving recompletions, gas lift enhancements and sliding sleeve shifts to change productive zones.

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 2011 totaled $12.9 million and ranged from $374 to $2,922 per well per month.

Fixed and Determinable Commitments

As of December 31, 2011 we had natural gas sales commitments to deliver fixed and determinable quantities of natural gas under term contracts as follows:

Year	Delivery Quantity (MMBTU)
2012	2,458,992
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. During 2011, 2010 and 2009, Shell Oil Company and affiliates accounted for 49%, 52% and 48% of our total oil and gas gross receipts, respectively. Flint Hills Resources accounted for approximately 14% of our total oil and gas gross receipts in 2011. No other purchasers accounted for more than 10% of our total oil and gas gross receipts for the past three years. Credit losses in each of the last three years were immaterial. 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 2011, we entered into gas processing and gathering agreements with Southcross Energy for a majority of our natural gas production in the AWP area, replacing agreements with Enterprise South Texas Pipeline and Enterprise Hydrocarbons. The processed liquids are sold to Southcross. The residue gas is sold at prevailing prices to Southcross and other parties at downstream connections with Southcross' system. Other gas production in the AWP area is processed or transported under arrangements with Houston Pipeline, DCP Midstream and Enterprise. 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.

In the Artesia Wells area, our oil production is sold at prevailing market prices and transported to market by truck. Natural gas is transported on Enterprise South Texas Pipeline or Eagle Ford Gathering, LLC. For volumes delivered to Eagle Ford Gathering, the processed liquids are purchased by Eagle Ford Gathering and residue gas sold to various parties at prevailing market prices. For deliveries to Enterprise, Enterprise purchases the processed liquids when processing is available, with the residue gas sold at prevailing market prices.

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 field is transported on barges for sales to various purchasers at prevailing market prices. Natural gas production is sold into an intrastate pipeline with prices tied to monthly and daily natural gas price indices.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil, NGL and natural gas production from our continuing operations for the three-year period ended December 31, 2011:

	Year Ended December 31,		
	2011	2010	2009
Net Sales Volume:			
Oil (MBbls)	3,865	3,905	4,346
Natural Gas Liquids (MBbls)	1,362	1,138	1,183
Natural gas (MMcf) 1	29,901	17,832	19,211
Total (MBoe)	10,211	8,015	8,731
Average Sales Price:			
Oil (Per Bbl)	$107.00	$79.45	$60.07
Natural Gas Liquids (Per Bbl)	$52.13	$42.44	$31.36
Natural gas (Per Mcf)	$3.94	$4.38	$3.83
Average Production Cost (Per Boe sold) 2	$10.26	$10.22	$8.79

1) Excludes gas consumed in operations that is included in reported production volumes of 1,898 MMcf in 2011, 1,889 MMcf in 2010 and 1,946 MMcf in 2009.

2) Excludes severance and ad valorem taxes

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, AWP Eagle Ford and Fasken fields in South Texas. These fields account for approximately 69% of the Company's proved reserves based on total Boe as of December 31, 2011:

	Year Ended December 31,		
	2011	2010	2009
AWP Olmos			
Net Sales Volume:			
Oil (MBbls)	376	256	197
Natural Gas Liquids (MBbls)	644	590	496
Natural gas (MMcf) 1	10,531	7,392	5,623
Total (MBoe)	2,775	2,078	1,630
Average Sales Price:			
Oil (Per Bbl)	$95.36	$76.88	$58.52
Natural Gas Liquids (Per Bbl)	$50.49	$40.52	$29.68

Natural gas (Per Mcf)	$3.98	$4.40	$3.63
Average Production Cost (Per Boe sold) 2	$9.53	$7.53	$6.51

1) Excludes gas consumed in operations that is included in reported production volumes of 232 MMcf in 2011, 235 MMcf in 2010 and 234 MMcf in 2009.
2) Excludes severance and ad valorem taxes

AWP Eagle Ford	Year Ended December 31, 2011	2010	2009
Net Sales Volume: 3			
Oil (MBbls)	400	155	---
Natural Gas Liquids (MBbls)	173	34	---
Natural gas (MMcf) 1	3,163	967	---
Total (MBoe)	1,100	350	---
Average Sales Price:			
Oil (Per Bbl)	$96.36	$76.96	$---
Natural Gas Liquids (Per Bbl)	$49.84	$37.89	$---
Natural gas (Per Mcf)	$4.04	$4.08	$---
Average Production Cost (Per Boe sold) 2	$6.92	$3.00	$---

1) Excludes gas consumed in operations that is included in reported production volumes of 48 MMcf in 2011 and one MMcf in 2010.
2) Excludes severance and ad valorem taxes
3) Production in the AWP Eagle Ford field began in 2010.

Fasken	Year Ended December 31, 2011	2010	2009
Net Sales Volume:			
Oil (MBbls)	---	---	---
Natural Gas Liquids (MBbls)	---	12	8
Natural gas (MMcf)	8,629	565	222
Total (MBoe)	1,438	106	45
Average Sales Price:			
Oil (Per Bbl)	$---	$---	$---
Natural Gas Liquids (Per Bbl)	$---	$37.15	$28.14
Natural gas (Per Mcf)	$3.62	$3.89	$3.70
Average Production Cost (Per Boe sold) 1	$3.36	$5.98	$12.58

1) 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, 2011, we had one oil price floor in effect that covers production of 81,500 barrels of oil for January 2012 with a strike price of $96.80.

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.

Employees

At December 31, 2011, we employed 309 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2011, 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 $475,000 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. Oil and natural gas prices 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. Thus far in 2012, there have been further declines in natural gas futures and spot prices. For example, the NYMEX January 2012 and February 2012 natural gas contracts settled at $3.08 per MMBtu and $2.68 per MMBtu, respectively. In addition, the quantity of natural gas currently being stored is at historically high levels relative to prior years.

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.

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. 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. If the variances in these assumptions are significant, many of which are based upon extrinsic events we cannot control, they could significantly affect these estimates.

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 future net cash flows from our oil and natural gas reserves.

At December 31, 2011, approximately 65% 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 Southeast Louisiana core areas could occasionally be affected by hurricane activity in the Gulf of Mexico, resulting in pipeline outages or damage to production facilities, causing production delays and/or significant repair costs.

Approximately 11% of our 2011 reserves and 30% of our 2011 production are located in our 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 (loss of production). 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.

Slower global economic growth rates may materially adversely impact our operating results and financial position.

The recovery from the global economic crisis of 2008 and resulting recession has been slow and uneven. Market volatility and reduced consumer demand have increased economic uncertainty, and the current global economic growth rate is slower than what was experienced in the years leading up to the crisis. A significant number of developed countries are constrained by long term structural government budget deficits and international financial markets and credit rating agencies are pressing for budgetary reform and discipline. This need for fiscal discipline is balanced by calls for continuing government stimulus and social spending as a result of the impacts of the global economic crisis. As major countries implement government fiscal reform, such measures if they are undertaken too rapidly, could further undermine economic recovery, reducing demand and slowing growth. Impacts of the crisis could spread to China and other emerging markets, which have fueled global economic development in recent years, slowing their growth rates, reducing demand, and resulting in further drag on the global economy.

Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate is likely to result in decreased demand growth for our crude oil and natural gas production. A decrease in demand, notwithstanding impacts from other factors, could potentially result in lower commodity prices, which would reduce our cash flows from operations, our profitability and our liquidity and financial position.

Our operations may be adversely affected by the European debt crisis

During 2011, the long term structural deficits in numerous European nations coupled with the deterioration of the economic outlook led the weaker nations to a liquidity and solvency crisis. Eurozone leaders have made numerous attempts to solve this debt crisis; but, to date a sustainable long term solution has not been implemented and much uncertainty remains. The crisis has had a negative impact on major European banks which historically were significant providers of credit to the energy sector, globally and in the US. On January 13, 2012, nine European nations had their credit ratings downgraded by Standard and Poor’s by at least one notch. Failure to successfully resolve the debt crisis could lead to significant losses for debt holders including major European banks and investors triggering additional capital requirements. In the worst case, the crisis could lead to the voluntary exit or expulsion of certain countries from the Euro currency block and/or a collapse of the Eurozone financial system. A break up of the Eurozone would be a deeply disruptive global economic event. The ongoing crisis continues to have a negative impact on the European economy. A prolonged downturn could disrupt the current US recovery and weaken global trade, hamper key emerging markets such as China and India, and result in another global recession with reduced demand and lower prices for the oil and gas we produce.

A Eurozone debt crisis could have the following impacts, among others:

- disruption of the Euro currency system and/or changes in currency regimes;
- disruption of the payment and settlement system;
- severe inflation due to currency depreciation;
- loss of access to energy markets;

- sovereign and corporate defaults on euro-denominated debt;
- failures of banks or financial systems or reduced ability of banks to lend due to higher funding costs;
- devaluation of assets; and
- regional economic recession which could spread globally.

The economic developments mentioned above could have a significant negative impact on our earnings, cash flows, access to capital, liquidity and financial position.

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. Although during 2011 we extended our line of credit through May 2016 and although it had a zero balance as of December 31, 2011, long-term restrictions, freezing of the capital markets, and legislation related to financial and banking reform 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 if we fail to 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 and carrying such insurance.

Our level of debt could reduce our financial flexibility.

As of December 31, 2011, our total debt comprised approximately 42% 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 contaminates
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions; and
- personal injuries and death.

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. 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. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. 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 2011 consisted of one oil price floor with a strike price of $96.80. 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.

A change in US energy policy can have a significant negative impact on our operations and profitability.

US energy policy and laws and regulations could change quickly. Currently, substantial uncertainty exists about the nature of potential rules and regulations that could impact the sources and uses of energy in the US. We design our exploration and development strategy and related capital investment programs years in advance. As a result, we are hindered in our ability to plan, invest and respond to potential changes in our business. This can result in a reduction of our cash flows and profitability to the extent we are unable to respond to sudden or significant changes in our operating environment due to changes in US energy policy.

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.

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 and 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.

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.

Hydraulic fracturing using fluids other than diesel is currently exempt from regulation under the federal Safe Drinking Water Act, but opponents of hydraulic fracturing have called for further study of the technique's environmental effects and, in some cases, a moratorium on the use of the technique. Several proposals have been submitted to Congress that, if implemented, would subject all hydraulic fracturing to regulation under the Safe Drinking Water Act. Further, the EPA's Office of Research and Development (ORD) is conducting a scientific study to investigate the possible relationships between hydraulic fracturing and drinking water. The ORD expects to have the initial study results available by late 2012. Also, various committees of Congress have been investigating hydraulic fracturing practices. Several states are considering legislation to regulate hydraulic fracturing practices, including restrictions on its use in environmentally sensitive areas. Some municipalities have significantly limited or prohibited drilling activities, or are considering doing so.

Although it is not possible at this time to predict the final outcome of the ORD's study or the requirements of any additional federal or state legislation or regulation regarding hydraulic fracturing, any new federal or state, or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business, such as the DJ Basin or Marcellus Shale areas, could significantly increase our operating, capital and compliance costs as well as delay or halt our ability to develop oil and gas reserves. See Items 1. and 2. Business and Properties

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 offsite 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.

Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of or recycle the water we use economically and in an environmentally safe manner.

Drilling activities require the use of fresh water. For example, the hydraulic fracturing process which we employ to produce commercial quantities of crude oil and natural gas from many reservoirs, including the Eagle Ford Shale, require the use and disposal of significant quantities of water. In certain areas, there may be insufficient aquifer capacity to provide a local source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site.

Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition. See Items 1. and 2. Business and Properties.

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.

Legal proceedings could result in liability affecting our results of operations

Most oil and gas companies, such as us, are involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. We defend ourselves vigorously in all such matters.

Because we maintain a portfolio of assets in the various areas in which we operate, the complexity and types of legal procedures with which we may become involved may vary, and we could incur significant legal and support expenses in different jurisdictions. If we are not able to successfully defend ourselves, there could be a delay or even halt in our exploration, development or production activities or other business plans, resulting in a reduction in reserves, loss of production and reduced cash flows. Legal proceedings could result in a substantial liability. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

A cyber incident could result in information theft, data corruption, operational disruption, and/or financial loss.

Businesses have become increasingly dependent on digital technologies to conduct day-to-day operations. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. A cyber attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial of service on websites.

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation, and for compliance reporting. The use of mobile communication devices has increased rapidly. The complexity of the technologies needed to extract oil and gas in increasingly difficult physical environments, such as shale, and global competition for oil and gas resources make certain information more attractive to thieves.

We depend on digital technology, including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, purchasers of our production and financial institutions, are also dependent on digital technology.

Our technologies, systems, networks, and those of our business partners may become the target of cyber attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- unauthorized access to seismic data, reserves information or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and gas resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in a dry hole cost or even drilling incidents;
- data corruption or operational disruption of production infrastructure could result in loss of production or accidental discharge;
- a cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt one of our major projects, effectively delaying the start of cash flows from the project;
- a cyber attack on a third party gathering or pipeline service provider could prevent us from marketing our production, resulting in a loss of revenues;
- a cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;
- a cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;
- a cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues; and
- a deliberate corruption of our financial or operational data could result in events of non-compliance which could lead to regulatory fines or penalties;
- significant business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

Although to date we have not experienced any material losses relating to cyber attacks, there can be no assurance that we will not suffer such losses in the future. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Item 1B. Unresolved Staff Comments

None.

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.

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

No matters were submitted during the fourth quarter of 2011 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, 2010 and 2011

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 2010 and 2011 were as follows:

	2010				2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$24.52	$26.17	$24.94	$27.99	$38.32	$33.07	$24.34	$21.81
High	$33.55	$38.17	$29.55	$40.83	$47.32	$42.96	$42.81	$32.78

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 170 stockholders of record as of December 31, 2011.

Stock Repurchase Table

The following table summarizes repurchases of our common stock occurring during the fourth quarter of 2011:

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)
10/01/11 – 10/31/11 1	1,110	$ 25,83	---	$ ---
11/01/11 – 11/30/11 1	1,013	$ 28.77	---	---
12/01/11 – 12/31/11 1	529	$ 30.19	---	---
Total	2,652	$ 27.82	---	$ ---

(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, 2011 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)	2011	2010	2009	2008	2007
Total Revenues from Continuing Operations (1)	$ 599,131	$ 438,429	$ 370,445	$ 820,815	$ 654,121
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$ 135,104	$ 74,308	$ (64,617)	$ (412,758)	$ 244,556
Income (Loss) from Continuing Operations (1)	$ 84,610	$ 46,475	$ (39,076)	$ (257,130)	$ 152,588
Net Cash Provided by Operating Activities - Continuing Operations	$ 373,058	$ 258,996	$ 226,176	$ 582,027	$ 442,282
Per Share and Share Data					
Weighted Average Shares Outstanding(1)	42,394	38,300	33,594	30,661	29,984
Earnings per Share--Basic(1)	$ 1.96	$ 1.19	$ (1.16)	$ (8.39)	$ 5.09
Earnings per Share--Diluted(1)	$ 1.95	$ 1.18	$ (1.16)	$ (8.39)	$ 4.98
Shares Outstanding at Year-End	42,485	41,999	37,457	30,869	30,179
Book Value per Share at Year-End	$ 23.46	$ 20.95	$ 18.12	$ 19.47	$ 27.70
Market Price					
High	$ 47.32	$ 40.83	$ 25.61	$ 67.03	$ 47.72
Low	$ 21.81	$ 24.52	$ 4.95	$ 15.30	$ 35.98
Year-End Close	$ 29.72	$ 39.15	$ 23.96	$ 16.81	$ 44.03
Assets					
Current Assets	$ 328,151	$ 158,358	$ 108,600	$ 78,086	$ 199,950
Property & Equipment, Net of Accumulated Depreciation, Depletion, and	$ 1,867,766	$ 1,572,845	$ 1,315,964	$ 1,431,447	$ 1,760,195

Amortization					
Total Assets	$ 2,212,469	$ 1,743,916	$ 1,434,765	$ 1,517,288	$ 1,969,051
Liabilities					
Current Liabilities	$ 211,794	$ 156,735	$ 103,604	$ 153,499	$ 210,161
Long-Term Debt	$ 719,775	$ 471,624	$ 471,397	$ 580,700	$ 587,000
Total Liabilities	$ 1,215,960	$ 863,899	$ 755,866	$ 916,411	$ 1,132,997
Stockholders' Equity	$ 996,509	$ 880,017	$ 678,899	$ 600,877	$ 836,054
Number of Domestic Employees	309	292	295	334	298
Domestic Producing Wells					
Swift Operated	1,025	1,212	1,146	1,168	1,091
Outside Operated	46	119	148	159	127
Total Domestic Producing Wells	1,071	1,331	1,294	1,327	1,218
Domestic Wells Drilled (Gross)	44	56	20	126	69
Domestic Proved Reserves					
Natural Gas (Bcf)	616.8	423.0	290.6	292.4	343.8
Oil Reserves (MBoe)	30.9	39.3	44.5	49.7	58.3
NGL Reserves (MBoe)	25.8	23.0	20.0	18.0	18.2
Total Domestic Proved Reserves (MMBoe equivalent)	159.6	132.8	112.9	116.4	133.8
Domestic Production (MMBoe equivalent)	10.5	8.3	9.1	10.0	10.6
Domestic Average Sales Price (2)					
Natural Gas (per Mcf produced)	$ 3.70	$ 3.96	$ 3.48	$ 8.54	$ 6.42
Natural Gas Liquids (per barrel)	$ 52.13	$ 42.44	$ 31.36	$ 57.15	$ 49.72
Oil (per barrel)	$ 107.00	$ 79.45	$ 60.07	$ 101.38	$ 71.92
Boe Equivalent	$ 57.22	$ 52.42	$ 41.05	$ 79.00	$ 61.49

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, 2011, 2010, and 2009 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 operations discontinued since late 2007. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 38 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 Eagle Ford shale and Olmos tight sands development. Oil production accounted for 37% of our 2011 production and 69% of our oil and gas revenues, and combined production of both oil and natural gas liquids ("NGLs") constituted 50% of our 2011 production and 80% of our oil and gas sales. This emphasis has allowed us to benefit from better margins for oil production than natural gas production during 2011.

2011 Highlights

- Production: Our 2011 production was 26% higher than 2010 volumes on a Boe basis, with the increased volumes mainly coming from natural gas and NGLs produced in our South Texas area.
- Increased reserves: Our year-end 2011 total proved reserves increased over our year-end 2010 reserves by 20% to a Company record of 159.6MMboe. This increase was mainly due to large increases in natural gas reserves in our South Texas area.
- Cash provided by operating activities: Increased by $114.1 million or 44%, as oil and NGL prices received in 2011 were 35% and 23% higher than the average prices we received in 2010 along with the impact of South Texas production increases.
- Disposition activity: In October 2011, we sold our interests in six fields in South Louisiana, two in Texas and one in Alabama for $48.8 million, net of $4.7 million in purchase price adjustments and the buyer's assumption of approximately $27.7 million of asset retirement obligations related to these properties.
    - 2011 debt issuance and available liquidity: We issued $250.0 million of 7-7/8% senior notes due 2022 in November 2011 at a discount of $2.1 million, leading to excellent liquidity leading into 2012.
- 2011 capital expenditures: Our capital expenditures on a cash flow basis were $505.3 million in 2011 compared to $353.6 million spent in 2010. The increase of $151.7 million was mainly due to additional drilling and completion activity in our South Texas core region as we drilled 12 horizontal wells in our AWP Olmos field, 17 wells in our AWP Eagle Ford field, six wells in our Fasken Eagle Ford field and three wells in our Artesia Eagle Ford field, helping us evaluate Eagle Ford and Olmos acreage positions in those areas. We also drilled two wells in our Southeast Louisiana area and four wells in our Central Louisiana/East Texas area. These 2011 expenditures were primarily funded by $373.1 million of cash provided by operating activities, asset disposition proceeds, and remaining cash proceeds from our stock offering in November 2010.

2012 Strategy and Outlook

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Focus on oil and liquids properties with expanded capital budget: Our inventory of drilling locations allows us to be flexible in scheduling upcoming wells to focus on liquids. . Having fulfilled our near-term obligations on most of our acreage prospective for dry natural gas production, we will be concentrating on our higher return, liquids rich acreage almost exclusively this year. Our 2012 capital expenditures are currently estimated to be $575 to $625 million with 75% to 80% focused on continued development in the liquids rich acreage in the Eagle Ford shale and the Olmos sands in our South Texas area.

- Increase production: Our current 2012 goal is to increase production volumes by 14% to 20% over 2011 volumes.
  - Increase reserves: Our current 2012 goal is to increase proved reserves volumes by 10% to 15%.
- Financial flexibility: At December 31, 2011, we have approximately $251.7 million of cash on hand and a commitment amount of $300.0 million under our credit agreement. These amounts give us the financial flexibility to execute our 2012 strategy.
- Added Mid-Stream capacity and third party providers: Additional dedicated transportation and processing through a newly constructed third-party pipeline of a mid-stream provider handling natural gas production from our AWP Eagle Ford and Olmos areas became operational at the beginning of October 2011. In our Fasken Eagle Ford area we also secured capacity on a pipeline built in late 2010 by a midstream provider. In both AWP Eagle Ford and Fasken Eagle Ford areas we have secondary transportation outlets available if capacity is restricted on our primary outlets.
- Highly skilled workforce: We have built a strong organization of highly skilled oil and gas professionals and also engage experienced and qualified consultants. These professionals are critical to us executing our 2012 goals.
- Capital cost saving measures: We have realized significant capital cost savings in South Texas related to pad drilling, well construction and completion re-design, sourcing and transportation of proppants as well as increased productivity of our dedicated frac spread and crew. Our supply chain program continues to be extremely important and the relationships that we have developed with our service providers are critical to our 2012 program execution.

2012 Known Trends and Uncertainties Affecting our Business

- Recent declines in natural gas prices: Several factors such as increases in shale and tight sands production, mild winter weather, and relatively high natural gas storage levels have led to declining natural gas prices in the fourth quarter of 2011 and into 2012. Futures prices for natural gas in 2012 are currently lower than our realized 2011 prices. We have not hedged our natural gas production and will receive a market price for natural gas in 2012. Lower natural gas prices equate to lower revenue and cash flows and might lead to reductions in our credit facility borrowing base. As natural gas makes up 64% of our reserves base on a Boe basis, lower natural gas prices in 2012 could lead to potential reserve reductions which could result in full-cost ceiling write-downs.
    - Employee retention: As our competitors expand their workforce, we must focus more attention on keeping our highly skilled employees. There has been and will be constant cost pressure to retain and hire these employees and these costs do not decline as rapidly and significantly as hydrocarbon prices.
- Oilfield services shortages and delays: During periods of increased levels of exploration and production in particular areas, such as we are currently experiencing in the South Texas areas, 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.
- Long-term capital commitments: In an effort to secure longer-term agreements on drilling rigs, fracturing services, equipment and supplies, our capital commitments have become more significant than in prior periods. Although these ensure that rigs and crews we need are available to use, these commitments may also reduce our liquidity in a downturn and may require us to pay above market prices for services in a declining service price environment.
- High concentration of sales with one customer: Over the last several years, a large portion of our oil and gas sales have been to Shell Oil Corporation and affiliates and we expect to continue this relationship in the future. We believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of their business.

Results of Operations

Revenues

2011.-Our revenues in 2011 increased by 37% compared to revenues in 2010 due to higher oil and NGL prices as well as higher NGL and natural gas production. Average oil prices that we received were 35% higher than those received during 2010, while natural gas prices were 6% lower, and NGL prices were 23% higher.

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 as a result of intentional reduction of drilling activity in 2009's low price environment. 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.

Crude oil production was 37% of our production volumes in 2011, 47% in 2010, and 48% in 2009. Crude oil sales were 69% of total sales in 2011, 71% in 2010, and 70% in 2009. Natural gas production was 50% of our production volumes in 2011, and 39% in both 2010 and 2009. Natural gas sales were 20% of sales in 2011, 18% in 2010, and 20% in 2009. The remaining production in each year was from natural gas liquids (NGLs).

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, 2011, 2010, and 2009:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2011	2010	2009	2011	2010	2009
S. E. Louisiana	$ 287.6	$ 246.2	$ 232.5	3,164	3,706	4,782
South Texas	225.3	120.4	77.4	5,937	3,235	2,721
Central and South Louisiana / East Texas	86.8	67.4	59.5	1,375	1,329	1,485
Other	2.6	2.6	2.3	51	60	67
Total	$ 602.3	$ 436.6	$ 371.7	10,527	8,330	9,055

In 2011, our $165.7 million increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $111.5 million favorable impact on sales, of which $106.4 million was attributable to the 35% increase in average oil prices received, $13.2 million was attributable to the 23% increase in NGL prices, reduced by $8.1 million due to the 6% decrease in average natural gas prices received; and
- Volume variances that had a $54.2 million favorable impact on sales, with $3.2 million of decreases attributable to the 0.04 million Bbl decrease in oil production volumes, $9.5 million of increase attributable to the 0.2 million Bbl increase in NGL production volumes and $47.8 million of increase attributable to the 12.1 Bcf increase in natural gas production volumes.

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
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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.

The following table provides additional information regarding our quarterly oil and gas sales from continuing operations excluding any effects of our hedging activities (which are minor in all periods):

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
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
2011:							
First	985	348	7.9	2,646	$ 98.61	$ 48.87	$ 3.82
Second	994	335	7.9	2,641	$ 112.09	$ 50.41	$ 3.93
Third	937	247	8.1	2,542	$ 105.55	$ 57.76	$ 3.68
Fourth	950	432	7.9	2,699	$ 111.79	$ 52.86	$ 3.39
Total	3,865	1,362	31.8	10,527	$ 107.00	$ 52.13	$ 3.70

During 2011, 2010, and 2009, we recognized net gains (losses) of ($0.9) million, $0.7 million, and ($1.4) 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 and losses been recognized in the oil and gas sales account, our average oil sales price would have been $106.81, $79.52 and $59.77 for 2011, 2010, and 2009, respectively, and our average natural gas price would have been $3.70, $3.98 and $3.47 for 2011, 2010, and 2009, respectively.

Costs and Expenses.

Our expenses in 2011 increased $99.9 million, or 27%, compared to 2010 expenses for the reasons noted below which was 10% less than the percentage increase in revenues between the two periods.

Lease Operating Expenses (“LOE”). These expenses increased 28%, compared to the level of such expenses in 2010, while 2010 costs increased 7% over 2009 levels. Lease operating costs increased during 2011 due to higher salt water disposal costs and higher transportations costs in South Texas. The increase in 2010 was due to higher workover costs and other cost increases from lease supervision and repair & maintenance. Our lease operating costs per Boe produced were $9.95, $9.84, and $8.47 in 2011, 2010, and 2009, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased 36% in 2011 from 2010 levels and decreased 2% in 2010 from 2009 levels. The increase in 2011 was due to a higher depletable base, higher production volumes and higher future development costs. The decrease in 2010 was due to lower production and higher reserves, partially offset by a higher depletion base. Our DD&A rate per Boe of production was $21.02 in 2011, $19.52 in 2010, and $18.34 in 2009, resulting from increases in per unit cost of reserves additions in 2011 and 2010.

General and Administrative Expenses, Net. These expenses increased 25%, from the level of such expenses in 2010, while 2010 expenses increased 7%, from the level of such expenses in 2009. The increase in 2011 was primarily due to higher performance based compensation and higher salaries and burdens. The increase in 2010 was primarily due to higher performance based compensation, partially offset by lower salaries and burdens. For the years 2011, 2010, and 2009, our capitalized general and administrative costs totaled $29.3 million, $24.6 million, and $24.5 million, respectively. Our net general and administrative expenses per Boe produced decreased to $4.31 per Boe in 2011 from $4.37 per Boe in 2010, but higher than $3.76 per Boe in 2009. The portion of supervision fees recorded as a reduction to general and administrative expenses was $12.9 million for 2011, $12.5 million for 2010, and $11.4 million for 2009.

Severance and Other Taxes. These expenses increased 14%, from 2010 levels, while in 2010 these taxes increased 11%, over 2009 levels. The increase in 2011 was due primarily to higher revenues from higher production and commodity prices. In 2010 the increases were due primarily to higher revenue from higher commodity prices. Severance and other taxes, as a percentage of oil and gas sales, were approximately 8.7%, 10.5% and 11.1% in 2011, 2010 and 2009, respectively. The decreases in 2011 and 2010 were 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.

Interest. Our gross interest cost in 2011 was $43.2 million, of which $7.7 million was capitalized. Our total 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. The increase in interest expense in 2011 was primarily due to interest on our new senior note due 2022 that were issued in November 2011.

Income Taxes. Our effective income tax rate was 37.4%, 37.5% and 39.5% for 2011, 2010 and 2009, 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 Ceiling Test Non-Cash Writedowns. 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.

Final Recognition of New Zealand Sales Proceeds. In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three $5.0 million payments spread over a 30 month period. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result in the second quarter of 2011, the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. As of December 31, 2011 all payments under this sale agreement had been received and 100% of the Company's oil and gas operations resided in the United States of America.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For 2011, our net cash provided by operating activities from continuing operations was $373.1 million, representing a 44% increase as compared to $259.0 million generated during 2010. The 2011 increase was primarily due to an increase of $165.7 million in oil and gas sales, mainly due to higher oil and NGL prices along with a significant increase in natural gas production. For 2010, our net cash provided by operating activities from continuing operations was $259.0 million, represented a 15% increase from the $226.2 million generated during 2009, with this increase 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.

Existing Credit Facility. In May 2011, we renewed and extended our $500 million credit facility with a syndicate of ten banks through May 12, 2016. During the May renewal, our borrowing base, as determined by our bank syndicate, was increased from $300 million to $400 million, and we elected to keep the commitment amount, which represents the limit on our borrowings without unanimous lender consent, at $300 million, all of which was reaffirmed in our November 2011 regularly scheduled borrowing base redetermination. The borrowing base was subsequently decreased at the end of November 2011 to $325 million, in accordance with the terms of our credit facility, due to the issuance of $250.0 million of 7-7/8% senior notes senior notes due in 2022. We had no amounts drawn under our credit facility as of December 31, 2011 and, as such, had $300 million of borrowing capacity. Our available borrowings under our 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. See note 4 of our consolidated financial statements for additional terms and restrictions of our credit facility.

2011 Debt Issuance. We issued $250.0 million of 7-7/8% senior notes due 2022 in November 2011 at a discount of 99.156% of face value. The proceeds from this debt issuance were recorded in “Cash and cash equivalents” on the accompanying consolidated balance sheet at December 31, 2011 and will be used to fund capital expenditures in 2012.

2010 and 2009 Public Stock Offerings. 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. 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, resulted in increased liquidity. In August 2009, 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. We used the proceeds from this stock sale to pay down a portion of the outstanding balance on our credit facility which, resulted in increased liquidity.

2009 Debt Issuance and Debt Retirement. We issued $225.0 million of 8-7/8% senior notes due 2020 in November 2009 at 98.389% of face value. In December 2009, we redeemed all $150.0 million of 7-5/8% senior notes due 2011.

Financial Ratios

Working Capital and Debt to Capitalization. Our working capital increased from a surplus of $1.6 million at December 31, 2010, to a surplus of $116.4 million at December 31, 2011. The change primarily resulted from an increase in cash and cash equivalents as we received cash from our debt offering in November 2011. 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. Not included in our working capital ratio is available liquidity through our credit facility. Our debt to capitalization ratio increased to 42% at December 31, 2011, as compared to 35% at December 31, 2010, primarily due to the 2011 debt issuance.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2011 are as follows:

	2012	2013	2014	2015	2016	Thereafter	Total
				(in thousands)			
Non-cancelable operating leases (1)	$ 6,183	$ 5,926	$ 5,773	$ 964	$ ---	$ —	$ 18,845
Asset retirement obligation (2)	9,279	6,317	5,785	5,299	4,854	44,860	76,394
Drilling rigs and completion services	55,967	2,952	801	—	—	—	59,720
Gas transportation and Processing (3)	5,559	8,074	8,343	5,749	4,316	—	32,041
Facility construction costs	2,016	—	—	—	—	—	2,016
7-1/8% senior notes due 2017	—	—	—	—	—	250,000	250,000
8-7/8% senior notes due 2020	—	—	—	—	—	225,000	225,000
7-7/8% senior notes due 2022	—	—	—	—	—	250,000	250,000
Interest Cost	52,602	57,469	57,469	57,469	57,469	187,078	469,556
Credit facility (4)	—	—	—	—	—	—	—

Total	$ 131,606	$ 80,738	$ 78,171	$ 69,481	$ 66,639	$ 956,938	$ 1,383,572

(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, 2011.
(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 May 2016 and these amounts exclude $0.9 million standby letters of credit outstanding under this facility.

As of December 31, 2011 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 58.0 MMBoe added in 2011, 36.7 MMBoe added in 2010, and 8.5 MMBoe added in 2009. The 2011 proved reserves additions from drilling activities consisted almost entirely of reserves additions within our South Texas area, most of which were proved undeveloped additions based on the results of the horizontal drilling program conducted in this area during the year. We obtained reasonable certainty regarding these reserves additions by applying the same methodologies that have been used historically in this area. At year-end 2011, 35% of our total proved reserves were proved developed, compared with 45% at year-end 2010 and 50% at year-end 2009.

At year-end 2011, our proved reserves were 159.6 MMBoe with a PV-10 Value of $1.9 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 $133 million from the prior year-end levels. In 2011, our proved natural gas reserves increased 193.8 Bcf, or 46%, while our proved oil reserves decreased 8.4 MMBbl, or 21%, and our NGL reserves increased 2.9 MMBbl, or 13%, for a total equivalent increase of 26.8 MMBoe, or 20%.

We use the preceding 12-months' average price based on closing prices on the first business day of each month in calculating our average prices used in the PV-10 calculation. Our average natural gas price used in the PV-10 calculation for 2011 was $3.89 per Mcf. This average price during 2011 was a decrease from $4.08 per Mcf at year-end 2010, compared to $3.78 per Mcf at year-end 2009. Our average oil price used in the PV-10 calculation for 2011 was $103.87 per Bbl. This average price during 2011 was an increase from $78.31 per Bbl at year-end 2010, compared to $59.76 in 2009.

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 the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials and 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, 2011 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.

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 the prices used in the Ceiling Test, even if only for a short period, it is reasonably possible that non-cash write-downs of oil and gas properties would 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, non-cash write-downs of our oil and natural gas properties would 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. There are no material new accounting pronouncements that have been issued but not yet adopted as of December 31, 2011.

Forward-Looking Information

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," “budgeted”, "expect," "may," continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in world oil markets and in oil and natural gas-producing countries;
- uncertainty regarding our future operating results;
- estimated future net reserves and present value thereof; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of Part I of this report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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 with some improvement in oil prices and high pricing volatility in natural gas through 2011. This pricing volatility has continued with natural gas prices while oil prices have seen significant improvement through the current period. See the Business and Properties section of this report – "Sensitivity of Domestic Reserves to Pricing."

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.

Price Floors – At December 31, 2011, we had one oil price floor in effect that covers production of 81,500 barrels of oil for January 2012 with a strike price of $96.80.

Interest Rate Risk. Our senior notes due 2017, 2020 and 2022 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, 2011, 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 future cash flows.

Income Tax Carryforwards. As of December 31, 2011, the Company has net tax carryforward assets of $45.5 million for federal net operating losses, $3.5 for federal alternative minimum tax credits and $7.5 million, net of a $3.9 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. Changes in markets conditions or significant changes in the Company's ownership could impact our ability to utilize these carryforwards.

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. Based upon quoted market prices as of December 31, 2011 and 2010, the fair value of our senior notes due 2017, was 254.8 million, or 101.9% of face value, and 254.7 million, or 101.9% of face value, respectively. Based upon quoted market prices as of December 31, 2011 and 2010, the fair value of our senior notes due 2020, was $239.6 million, or 106.5% of face value and $242.3 million, or 107.7% of face value, respectively. Based upon quoted market prices as of December 31, 2011, the fair value of our senior notes due 2022, was 252.8 million, or 101.1% of face value. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2011 and 2010, while the carrying value of our senior notes due 2020 was $221.9 million and $221.6 million at December 31, 2011 and 2010, respectively, and the carrying value of our senior notes due 2022 was $247.9 million at December 31, 2011.

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 and 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.

Item 8. Financial Statements and Supplementary Data | Page

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, 2011. 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, 2011.

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, 2011, 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, 2011, 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, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 23, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 23, 2012

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, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009 the Company 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, 2011, 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 23, 2012 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 23, 2012

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

	As of December 31, 2011	2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 251,696	$ 86,367
Accounts receivable	64,392	46,975
Deferred tax assets	6,603	6,347
Other current assets	5,460	18,105
Current assets held for sale	---	564
Total Current Assets	328,151	158,358
Property and Equipment:		
Property and Equipment	4,466,845	3,951,107
Less – Accumulated depreciation, depletion, and amortization	(2,599,079)	(2,378,262)
Property and Equipment, Net	1,867,766	1,572,845
Other Long-Term Assets	16,552	12,713
Total Assets	2,212,469	$ 1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 95,966	$ 75,594
Accrued capital costs	98,844	64,879
Accrued interest	12,459	11,010
Undistributed oil and gas revenues	4,525	5,252
Total Current Liabilities	211,794	156,735
Long-Term Debt	719,775	471,624
Deferred Income Taxes	206,567	157,565
Asset Retirement Obligation	67,115	70,171
Other Long-Term Liabilities	10,709	7,804
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	---	---
Common stock, $.01 par value, 150,000,000 and 85,000,000 shares authorized, 42,969,546 and 42,440,583 shares issued, and 42,485,075 and 41,999,058 shares outstanding, respectively	430	424
Additional paid-in capital	726,956	706,857
Treasury stock held, at cost, 484,471 and 441,525 shares, respectively	(12,350)	(9,778)

Retained earnings		281,473		182,652
Accumulated other comprehensive loss, net of income tax		---		(138)
Total Stockholders' Equity		996,509		880,017
Total Liabilities and Stockholders' Equity	$	2,212,469	$	1,743,916

See accompanying notes to consolidated financial statements.

47

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

	Year Ended December 31,		
	2011	2010	2009
Revenues:			
Oil and gas sales	$ 602,341	$ 436,632	$ 371,749
Price-risk management and other, net	(3,210)	1,797	(1,304)
Total Revenues	599,131	438,429	370,445
Costs and Expenses:			
General and administrative, net	45,362	36,359	34,046
Depreciation, depletion, and amortization	221,230	162,572	166,108
Accretion of asset retirement obligation	4,570	3,956	2,906
Lease operating cost	104,791	81,929	76,740
Severance and other taxes	52,508	45,868	41,326
Interest expense, net	35,566	33,437	30,663
Debt retirement cost	---	---	3,961
Write-down of oil and gas properties	---	---	79,312
Total Costs and Expenses	464,027	364,121	435,062
Income (Loss) from Continuing Operations Before Income Taxes	135,104	74,308	(64,617)
Provision (Benefit) for Income Taxes	50,494	27,833	(25,541)
Income (Loss) from Continuing Operations	84,610	46,475	(39,076)
Income (Loss) from Discontinued Operations, net of taxes	14,211	(181)	(254)
Net Income (Loss)	$ 98,821	$ 46,294	$ (39,330)
Per Share Amounts-			
Basic: Income (Loss) from Continuing Operations	$ 1.96	$ 1.19	$ (1.16)
Gain (Loss) from Discontinued Operations, net of taxes	0.33	(0.00)	(0.01)
Net Income (Loss)	$ 2.29	$ 1.19	$ (1.17)
Diluted: Income (Loss) from Continuing Operations	$ 1.95	$ 1.18	$ (1.16)
Gain (Loss) from Discontinued Operations, net of taxes	0.33	(0.00)	(0.01)
Net Income (Loss)	$ 2.27	$ 1.18	$ (1.17)

Weighted Average Shares Outstanding	42,394	38,300	33,594
See accompanying notes to consolidated financial statements.			

48

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, 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
	-	242	1,271	-	-	1,513

Stock issued for benefit plans (59,335 shares)						
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
Stock issued for benefit plans (37,068 shares)	-	791	821	-	-	1,612
Stock options exercised (130,902 shares)	1	1,150	-	-	-	1,151
Purchase of treasury shares (80,014 shares)	-	-	(3,393)	-	-	(3,393)
Tax benefits from stock compensation	-	333	-	-	-	333
Employee stock purchase plan (49,089 shares)	1	999	-	-	-	1,000

Issuance of restricted stock (348,972 shares)	4	(4)	-	-	-	-
Amortization of stock compensation	-	16,830	-	-	-	16,830
Net Income	-	-	-	98,821	-	98,821
Other comprehensive income	-	-	-	-	138	138
Total comprehensive income						98,959
Balance, December 31, 2011	$ 430	$ 726,956	$ (12,350)	$ 281,473	-	$ 996,509

(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,		
	2011	2010	2009
Cash Flows from Operating Activities:			
Net income (loss)	$ 98,821	$ 46,294	$ (39,330)
Plus (gain) loss from discontinued operations, net of taxes	(14,211)	181	254
Adjustments to reconcile net income (loss) to net cash provided by operation activities -			
Depreciation, depletion, and amortization	221,230	162,572	166,108
Write-down of oil and gas properties	-	-	79,312
Accretion of asset retirement obligation	4,570	3,956	2,906
Deferred income taxes	48,995	32,881	(13,377)
Stock-based compensation expense	12,625	10,256	9,232
Debt retirement cost – cash and non-cash	---	---	3,961
Other	2,143	1,563	16,133
Change in assets and liabilities-			
(Increase) decrease in accounts receivable	(12,625)	(6,691)	2,666
Increase in accounts payable and accrued liabilities	10,134	472	1,977
Increase (decrease) in income taxes payable	(73)	247	(204)
Increase (decrease) in accrued interest	1,449	7,265	(3,462)
Cash provided by operating activities – continuing operations	373,058	258,996	226,176
Cash used in operating activities – discontinued operations	(2)	(41)	(396)
Net Cash Provided by Operating Activities	373,056	258,955	225,780
Cash Flows from Investing Activities:			
Additions to property and equipment	(505,332)	(353,648)	(215,370)
Proceeds from the sale of property and equipment	50,284	133	31,083
Acquisition of properties	---	---	---
Cash used in investing activities – continuing operations	(455,048)	(353,515)	(184,287)
Cash provided by investing activities – discontinued operations	5,000	5,000	5,000
Net Cash Used in Investing Activities	(450,048)	(348,515)	(179,287)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	247,890	---	221,375
Payments of long-term debt	---	---	(150,000)
Net payments of bank borrowings	---	---	(180,700)
Net proceeds from issuances of common stock	2,151	142,917	109,801
Purchase of treasury shares	(3,393)	(1,828)	(884)

Payments of debt retirement costs		---		---		(2,859)
Payments of debt issuance costs		(4,327)		(3,631)		(5,040)
Cash provided by (used in) financing activities – continuing operations		242,321		137,458		(8,307)
Cash provided by financing activities – discontinued operations		---		---		---
Net Cash provided by (used in) financing activities		242,321		137,458		(8,307)
Net Increase in Cash and Cash Equivalents	$	165,329	$	47,898	$	38,186
Cash and Cash Equivalents at Beginning of Year		86,367		38,469		283
Cash and Cash Equivalents at End of Year	$	251,696	$	86,367	$	38,469
Supplemental Disclosures of Cash Flows Information:						
Cash paid during year for interest, net of amounts capitalized	$	32,078	$	24,622	$	32,885
Cash paid during year for income taxes	$	1,770	$	200	$	233
See accompanying notes to consolidated financial statements.						

50

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 gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in oil and gas properties 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 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 sales, 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 share-based 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 2011, 2010, and 2009, such internal costs capitalized totaled $29.3 million, $24.6 million, and $24.5 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years 2011, 2010, and 2009, capitalized interest on unproved properties totaled $7.7 million, $7.4 million, and $6.1 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, 2011	December 31, 2010
Property and Equipment		
Proved oil and gas properties	$ 4,343,867	$ 3,835,173
Unproved oil and gas properties	84,146	78,429
Furniture, fixtures, and other equipment	38,832	37,505
Less – Accumulated depreciation, depletion, and amortization	(2,599,079)	(2,378,262)
Property and Equipment, Net	$ 1,867,766	$ 1,572,845

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 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 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 price differentials and 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 in place at year-end 2011 and 2010 consisted of 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 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.

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 reasonably possible that non-cash write-downs of oil and natural gas properties would 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, non-cash write-downs of our oil and natural gas properties would 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, 2011 and 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.

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, 2011 and 2010, 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, 2011 our “Accounts Receivable” balance included $54.7 million for oil and gas sales, $4.2 million for joint interest owners and $5.6 million for other receivables. 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.

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, 2011, was $2.6 million, net of accumulated amortization of $1.5 million. The 8-7/8% senior notes due 2020 mature on January 15, 2020, and the balance of their issuance costs at December 31, 2011, was $4.3 million, net of accumulated amortization of $0.7 million. The 7-7/8% senior notes due 2022 mature on March 1, 2022, and the balance of their issuance costs at December 31, 2011, was $4.7 million, net of accumulated amortization of less than $0.1 million. The issuance costs associated with our revolving credit facility, which was revised and extended in May 2011, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2011, was $3.5 million, net of accumulated amortization of $4.0 million.

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 2011, 2010, and 2009, we recognized net gains (losses) of ($0.9) million, $0.7 million, and ($1.4) 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 (losses) been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. At December 31, 2011, the Company did not have any derivative gains (losses) in "Accumulated other comprehensive loss, net of income tax" on the accompanying consolidated balance sheets. 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 2011, 2010 and 2009 was not material.

At December 31, 2011, we had one oil price floor in effect that covers production of 81,500 barrels of oil for January 2012 with a strike price of $96.80.

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 are 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, 2011 and 2010, was $0.1 million and $0.3 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 for 2011 and 2010 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operate was $12.9 million in 2011, $12.5 million in 2010, and $11.4 million in 2009.

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) are included in "Other current assets" on the accompanying consolidated balance sheets totaling $3.6 million and $12.8 million at December 31, 2011 and 2010, respectively.

During 2011 we recorded a charge of $2.1 million related to inventory obsolescence in "Price-risk management and other, net" on the accompanying condensed statement of operations.

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, 2011, 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. The "Accounts Payable and Accrued Liabilities" balances on the accompanying consolidated balance sheets are summarized below for presentation purposes. The following is a detailed breakout of certain items within "Accounts Payable and Accrued Liabilities" in the corresponding periods:

(in thousands)	December 31, 2011	December 31, 2010
Trade accounts payable (1)	$ 42,080	$ 22,459
New Zealand deferred revenue	---	10,000
Accrued operating expenses	15,833	11,044
Accrued payroll costs	14,345	14,298
Asset retirement obligation – current portion	9,279	8,708
Accrued taxes	7,604	7,198
Other payables	6,825	1,887
Total accounts payable and accrued liabilities	$ 95,966	$ 75,594

(1) Included in "trade accounts payable" are liabilities of approximately $18.7 million and $8.1 million at December 31, 2011 and December 31, 2010, respectively, for outstanding checks. This represents the amounts by which checks were 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 2011, 2010 and 2009, Shell Oil Company and affiliates accounted for 49%, 52% and 48% of our total oil and gas gross receipts, respectively. Flint Hills Resources accounted for approximately 14% of our total oil and gas gross receipts in 2011. No other purchasers accounted for more than 10% of our total oil and gas gross receipts for the past three years. 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, 2011 and 2010 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, 2011, the Company had no gains or losses in “Accumulated other comprehensive income (loss), net of income tax” on the accompanying consolidated balance sheet. The components of accumulated other comprehensive loss and related tax effects for 2011 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive gain (loss) at December 31, 2010	$ (218)	$ 80	$ (138)
Change in fair value of cash flow hedges	(520)	190	(330)
Effect of cash flow hedges settled during the period	738	(270)	468
Other comprehensive gain (loss) at December 31, 2011	$ ---	$ ---	$ ---

Total comprehensive income (loss) was $99.0 million, $46.4 million and ($39.6) million for 2011, 2010, and 2009, 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 "Property and equipment" balance on our accompanying consolidated balance sheets. 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, 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 estimates	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 estimates	10,149
Asset Retirement Obligation as of December 31, 2010	$78,879
Accretion expense	4,570

Liabilities incurred for new wells and facilities construction	590
Reductions due to sold and abandoned wells	(28,194)
Revisions in estimates	20,548
Asset Retirement Obligation as of December 31, 2011	$76,393

During 2011 we performed our annual revaluation of the asset retirement obligation, increasing the liability as a result of an increase in the expected abandonment costs for some of our wells and facilities and a decrease in the expected timing of abandonment activities for wells and facilities in certain fields. This revaluation increase is shown above as "Revisions in estimates."

In 2011 we sold our interests in six fields in South Louisiana, two in Texas and one in Alabama which included the buyer's assumption of approximately $27.7 million of asset retirement obligations related to these properties. This decrease is shown above in "Reductions due to sold and abandoned wells."

At December 31, 2011 and 2010, approximately $9.3 million and $8.7 million, respectively, of our asset retirement obligation are classified as a current liability in "Accounts payable and accrued liabilities" on the accompanying consolidated balance sheets.

Public Stock Offerings. 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 June 2011, the FASB issued ASU No. 2011-05, which changes the required presentation of other comprehensive income. Under the new guidelines, entities will be required to present net income and other comprehensive income, along with the components of net income and other comprehensive income, in either one continuous statement of comprehensive income or in two separate but consecutive statements of net income and comprehensive income. The accounting standards update eliminates the option of presenting the components of other comprehensive income within the statement of changes in stockholders' equity. We will adopt this guidance for the period ending March 31, 2012, although early adoption is permitted, and do not expect the guidance to have a material impact on our financial position or results of operations.

In May 2011, the FASB issued ASU No. 2011-04 to provide additional guidance related to fair value measurements and disclosures. The guidance, which is incorporated into FASB ASC 820-10, generally provides clarifications to existing fair value measurement and disclosure requirements and also creates or modifies other fair value measurement and disclosure requirements. We will adopt this guidance, as required, for the period ending March 31, 2012 and do not expect the guidance to have a material impact on our financial position or results of operations.

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 year of adoption. 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 basic 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.

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, 2011 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 year ended December 31, 2009, 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 years ended December 31, 2011 and 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, 2011, 2010 and 2009 (in thousands, except per share amounts) from continuing operations:

	2011			2010			2009		
	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	$84,610	42,394		$46,475	38,300		$(39,076)	33,594	
Less: Income (Loss) from continuing operations allocated to unvested shareholders	(1,598)	---		(879)	---		---	---	
Income (Loss) from continuing operations allocated to common shares	$83,012	42,394	$1.96	$45,596	38,300	$1.19	$(39,076)	33,594	$(1.16)
Dilutive Securities:									
Plus: Income (Loss) from continuing operations allocated to unvested shareholders	1,598			879					
Less: Income (Loss) from continuing operations re-allocated to unvested shareholders									
	(1,589)	235		(874)	224		--	--	

Stock Options									
Diluted EPS:									
Net Income (Loss) from continuing operations, and assumed share conversions	$83,021	42,629	$1.95	$45,601	38,524	$1.18	$(39,076)	33,594	$(1.16)

Options to purchase approximately 1.4 million shares at an average exercise price of $32.46 were outstanding at December 31, 2011, while options to purchase approximately 1.4 million shares at an average exercise price of $29.67 were outstanding at December 31, 2010, and options to purchase 1.3 million shares at an average exercise price of $29.72 were outstanding at December 31, 2009. Approximately 0.8 million and 0.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2011 and 2010, respectively, 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 stock options to purchase shares were not included in the computation of Diluted EPS for the year ended December 31, 2009, as they would be antidilutive given the net loss from continuing operations.

Employee restricted stock grants of 0.2 million and 0.1 million shares were not included in the computation of Diluted EPS for the years ended December 31, 2011 and 2010, respectively, 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 shares of employee restricted stock outstanding at December 31, 2009, 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, 2011	2010	2009
Income (Loss) from Continuing Operations Before Income Taxes	$ 135,104	$ 74,308	$ (64,617)

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

	Year Ended December 31, 2011	2010	2009
Current	$ 1,616	$ (2,957)	$ (10,792)
Deferred	48,878	30,790	(14,749)
Total	$ 50,494	$ 27,833	$ (25,541)

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. Under the provisions of this act, the Company carried back its 2008 Federal net operating loss four years. However, upon IRS audit of these refunds, it was discovered that the Company could only carry back its 2008 Federal Net operating loss two years resulting in a charge in current expense during 2011. The 2010 refund and 2011 payments were primarily attributable to alternative minimum tax. 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):

	Year Ended December 31, 2011	2010	2009
Income taxes (or benefits) computed at U.S. statutory rate (35%)	$ 47,282	$ 26,008	$ (22,616)
State tax provisions (benefits), net of federal benefits	1,505	641	(1,956)
Cumulative impact of adjustments to net state income tax rate	(2,663)	(1,718)	---
Valuation allowance of carryover tax assets	2,273	1,681	(1,082)
Non-deductible equity compensation	1,537	867	105
Other, net	560	354	8

Provision (benefit) for income taxes	$ 50,494	$ 27,833	$ (25,541)
Effective rate	37.4 %	37.5 %	39.5 %

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 $1.5 million and $0.6 million for 2011 and 2010, respectively, and a credit of $2.0 million for 2009. Non-deductible equity compensation increased tax expense by $1.5 million for 2011, $0.9 million for 2010, and by $0.1 million for 2009. Revisions in the Company's long-term state apportionment rates resulted in a reduction to Louisiana income tax deferred liabilities of $2.7 million and $1.7 million in 2011 and 2010, respectively. However, these adjustments also reduced our future expectation to realize benefits for Louisiana state tax loss carryovers. Accordingly we took a charge of $2.3 million and $1.7 million for 2011 and 2010, respectively, 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, 2011 and 2010 were as follows (in thousands):

	2011	2010
Deferred tax assets:		
Federal net operating losses (“NOLs”)	$ 54,954	$ 30,715
NOLs for excess stock-based compensation	(9,450)	(7,590)
Alternative minimum tax credits	3,451	2,092
Carryover items, net of valuation allowance	8,617	8,823
Unrealized stock compensation	7,151	5,519
Other	7,580	7,026
Total deferred tax assets	$ 72,303	$ 46,585
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ (270,158)	$ (195,454)
Other	(2,109)	(2,349)
Total deferred tax liabilities	$ (272,267)	$ (197,803)
Net deferred tax liabilities	$ (199,964)	$ (151,218)
Net current deferred tax assets	6,603	6,347
Net non-current deferred tax liabilities	$ (206,567)	$ (157,565)

Deferred tax assets increased by $25.7 million. The federal net operating loss tax assets, net of NOLs for excess stock-based compensation, increased by $22.3 million due to a current year tax operating loss. Current income taxes paid were for primarily for Alternative Minimum Tax (AMT) which increased credits available for future years by $1.4 million.

The total change in the deferred liability from 2010 to 2011 was an increase of $74.5 million. This increase is primarily attributable to a $74.7 million increase in the deferred liability for oil and gas exploration and development costs. This increase is attributable to accelerated tax deductions for oil and natural gas exploration and development costs.

The federal net operating losses will expire between 2027 and 2031 if not utilized in earlier periods. The Company’s federal NOL tax assets for 2011, 2010 and 2009 were $55.0 million, $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 $9.5 million for 2011, $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 $7.5 million net asset, net of a $3.9 million valuation allowance for State of Louisiana net operating loss carryovers. These loss carryforwards are scheduled to expire between 2013 and 2026.

Unrealized stock compensation accounts for $7.2 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.

As of December 31, 2011, The Internal Revenue Service (IRS) had completed their examination of the Company’s 2008 U.S. income tax returns which commenced in October 2010. There are no items under dispute related to this audit. Due to statutory requirements regarding IRS audits involving refunds of tax in excess of $2 million the IRS has submitted a report regarding the Company’s case to the United States Congress Joint Committee on Taxation (“Joint Committee”). Although not required by statue, the IRS standard practice is to comply with any significant adjustments requested by the Joint Committee. Therefore the IRS will not officially close the audit until the Joint Committee review is completed.

4. Long-Term Debt

Our long-term debt as of December 31, 2011 and 2010 is as follows (in thousands):

		2011		2010
7-1/8% senior notes due 2017	$	250,000	$	250,000
8-7/8% senior notes due 2020 1		221,873		221,624
7-7/8% senior notes due 2022 1		247,902		---
Bank Borrowings		---		---
Long-Term Debt 1	$	719,775	$	471,624

(1) Amounts are shown net of debt discount

The maturities on our long-term debt are $250.0 million in 2017, $225.0 million in 2020 and $250.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $7.7 million, $7.4 million and $6.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Bank Borrowings. In May 2011, we renewed and extended our $500 million credit facility with a syndicate of ten banks through May 12, 2016, which may be increased by up to $200 million to a maximum aggregate facility amount of $700 million, subject to additional lender commitments and other terms of the credit agreement. During the May renewal, our borrowing base, as determined by our bank syndicate, was increased from $300 million to $400 million, and we elected to keep the commitment amount, which represents the limit on our borrowings without unanimous lender consent, at $300 million. In November 2011, in conjunction with our regularly scheduled borrowing base redetermination which occurs every six months, our borrowing base was reaffirmed at $400 million and we again elected to keep our commitment amount $300 million. The borrowing base subsequently decreased at the end of November 2011 to $325 million, in accordance with the terms of our credit facility, when we issued $250.0 million of 7-7/8% senior notes senior notes due in 2022.

At December 31, 2011 and 2010 we had no borrowings under our credit facility. The interest rate on our credit facility is either (a) the lead bank’s prime plus an applicable margin or (b) Eurodollar rate 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 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. The commitment fee associated with the unfunded portion of the borrowing base is set at 50 basis points. At December 31, 2011, 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. As of December 31, 2011 we were 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 with unanimous consent of the bank group as it might change from time to time.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.4 million in 2011, $1.9 million in 2010, and $5.2 million in 2009. The amount of commitment fees included in interest expense, net was $1.5 million in 2011, $1.4 million in 2010 and $0.7 million in 2009.

Senior Notes Due 2022. These notes consist of $250 million of 7-7/8% senior notes issued at 99.156% of par, which equates to an effective yield to maturity of 8%. The notes were issued on November 30, 2011 with an original discount of $2.1 million and will mature on March 1, 2022. The original discount of $2.1 million is recorded in "Long-Term Debt" on our consolidated balance sheet 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. Payment of interest on these notes is payable semi-annually on March 1 and September 1 and will commence on March 1, 2012. On or after March 1, 2017, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter. In addition, prior to March 1, 2015, 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 107.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $4.8 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying consolidated balance sheet 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 were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2011.

Interest expense on the 7-7/8% senior notes due 2022, including amortization of debt issuance costs and debt discount, totaled $1.7 million for the year ended December 31, 2011.

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. Payment of 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 were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2011.

Interest expense on the 8-7/8% senior notes due 2020, including amortization of debt issuance costs and debt discount, totaled $20.6 million, $20.5 million and $2.0 million for the years ended December 31, 2011, 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. Payment of 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 were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2011.

Interest expense on the 7-1/8% senior notes due 2017, including amortization of debt issuance costs, totaled $18.2 million, $18.4 million and $18.1 million for the years ended December 31, 2011, 2010 and 2009.

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.

5. Commitments and Contingencies

Rental and lease expenses which were included in "General and administrative, net" on our accompanying consolidated statements of operations were $5.6 million in 2011, $5.4 million in 2010, and $4.2 million in 2009. Rental and lease expenses which were included in "Lease operating cost" on our accompanying consolidated statements of operations were $13.9 million in 2011 and $10.5 million in both 2010 and 2009. Our remaining minimum annual obligations under non-cancelable operating lease commitments were $6.2 million for 2012, $5.9 million for 2013, $5.8 million for 2014, $1.0 million for 2015 and $18.8 million in total. 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, 2011 for these services and materials totaled $59.7 million through 2014.

Our employment agreement liabilities constitute the majority of other long-term liabilities on the balance sheet at both December 31, 2011 and 2010.

Our remaining gas transportation and processing minimum obligations were $5.6 million for 2012, $8.1 million for 2013, $8.3 million for 2014, $5.7 million for 2015, $4.3 million for 2016 and $32.0 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 49,089 shares at a price of $20.37 in 2011, 66,564 shares at a price of $14.29 in 2010 and 50,690 shares at a price of $14.29 in 2009. The contributions in 2011, 2010, and 2009 and were all made in common stock, from treasury shares. As of December 31, 2011, 49,754 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 market value on the exercise date 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. For the years ended December 31, 2011, 2010 and 2009, we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were $1.2 million, $2.1 million, and $0.3 million for the years ended December 31, 2011, 2010, and 2009 respectively. The actual income tax benefit from stock option exercises was $1.1 million, $0.8 million, and $0.1 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 $11.9 million, $9.3 million, and $8.4 million for the years ended December 31, 2011, 2010, and 2009, respectively. Stock compensation recorded in lease operating cost was $0.3 million for both years ended December 31, 2011 and 2010 and $0.4 million for the year ended December 31, 2009. We also capitalized $4.2 million, $1.6 million, and $2.1 million of stock compensation in 2011, 2010, and 2009, respectively.

Our shares available for future grant under our stock compensation plans were 2,349,146 at December 31, 2011. 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,		
	2011	2010	2009
Dividend yield	0 %	0 %	0 %
Expected volatility	58.8 %	62.8 %	50.5 %
Risk-free interest rate	1.9 %	2.1 %	1.8 %
Expected life of options (in years)	3.8	4.3	4.5
Weighted-average grant-date fair value	$ 19.17	$ 12.60	$ 6.32

The expected term for grants issued post 2008 has been based on an analysis of historical employee exercise behavior and considered all relevant factors including expected future employee exercise behavior. 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 2011, 2010 and 2009 stock option grants.

At December 31, 2011, there was $2.2 million of unrecognized compensation cost related to stock options which is expected to be recognized over a weighted-average period of 0.6 years. The following table represents stock option activity for the years ended December 31, 2011, 2010 and 2009:

	2011		2010		2009	
	Shares	Wtd Avg. Exer. Price	Shares	Wtd, Avg Exer. Price	Shares	Wtd. Avg Exer. Price
Options outstanding, beginning of period	1,361,779	$ 29.67	1,289,194	$ 29.72	1,119,469	$ 33.22
Options granted	307,394	$ 42.56	273,463	$ 25.28	273,400	$ 14.66
Options canceled	(67,529)	$ 55.19	(36,983)	$ 44.65	(77,619)	$ 33.26
Options exercised1	(226,363)	$ 22.61	(163,895)	$ 18.11	(26,056)	$ 12.52
Options outstanding, end of period	1,375,281	$ 32.46	1,361,779	$ 29.67	1,289,194	$ 29.72
Options exercisable, end of period	734,985	$ 31.07	749,447	$ 32.04	790,394	$ 31.00

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 2011 and 2010, 79,194 and 27,463 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, 2011 was $6.4 million and 5.8 years and $4.2 million and 4.2 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2011 was $4.2 million.

The following table summarizes information about stock options outstanding at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/11	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/11	Wtd. Avg. Exercise Price
$8.00 to $24.99	557,530	5.9	$18.65	302,388	$16.67
$25.00 to $44.99	762,350	6.0	$41.38	393,055	$40.28
$45.00 to $65.00	55,401	1.1	$48.64	39,542	$49.55
$8.00 to $65.00	1,375,281	5.8	$32.46	734,985	$31.07

Restricted Stock. In 2011, 2010 and 2009, the Company issued 499,050, 388,650 and 433,210 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 $40 per share in 2011, $25 per share in 2010 and $12 per share in 2009.

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, 2011, we have unrecognized compensation expense of approximately $15.7 million associated with these awards which are expected to be recognized over a weighted-average period of 1.0 years. The total fair value of shares vested during the year ended December 31, 2011 was $8.7 million.

The following is a summary of our restricted stock issued to employees, consultants, and directors under these plans as of December 31, 2011, 2010, and 2009:

	2011		2010		2009	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	734,286	$22.87	703,856	$24.15	586,325	$42.78
Restricted shares granted	499,050	$40.28	388,650	$25.41	433,210	$12.48
Restricted shares canceled	(49,661)	$32.29	(46,029)	$24.45	(51,750)	$41.86
Restricted shares vested	(348,972)	$24.84	(312,191)	$28.75	(263,929)	$42.92
Restricted shares outstanding, end of period	834,703	$31.89	734,286	$22.87	703,856	$24.15

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, 2011, 2010 and 2009, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2011, 2010 and 2009, and were all made in common stock, from treasury shares, 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, from treasury shares, totaled 6,729, 5,108 and 8,347 shares for the 2011, 2010, and 2009 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 $1.4 million for 2011 and $1.3 million for both 2010 and 2009, and are recorded as "General and administrative, net" on the accompanying consolidated statements of operations. The contributions in 2011, 2010, and 2009 and were all made in common stock, from treasury shares. The shares of common stock contributed to the 401(k) savings plan totaled 44,258, 31,960 and 50,988 shares for the 2011, 2010, and 2009 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, 2011, 484,471 shares remain in treasury (net of 763,083 shares used to fund the ESOP and 401(k) contributions) with a total cost of $12.4 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 Tec-Com, for services pursuant to the terms of the contract, approximately $0.6 million in 2011, 2010 and 2009. 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 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. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result, in the second quarter of 2011 the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. 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. As of December 31, 2011 all payments under this sale agreement had been received. There is essentially no income tax expense on this gain as the Company has offsetting New Zealand tax losses that were previously unrecognized due to a valuation allowance. The Company has written off its remaining unused New Zealand tax losses.

Our income from discontinued operations was $14.2 million for the year ended December 31, 2011, which equated to $0.33 per basic and diluted share for the period. Our loss from discontinued operations, net of taxes was $0.2 million for the year ended December 31, 2010, which equated to $0.00 per basic and diluted share for the period. Our loss from discontinued operations, net of taxes was $0.3 million for the year ended December 31, 2009, which equated to $0.01 per basic and diluted share for the period. Our cash used in operating activities – discontinued operations was less than $0.1 million for the years ended December 31, 2011 and 2010 and was $0.4 million for the year ended December 31, 2009.

9. Acquisitions and Dispositions

In October 2011, we closed the sale of certain properties located in Louisiana, Texas and Alabama. The fields in Louisiana include Horseshoe Bayou/Bayou Sale, High Island, Bayou Penchant, Jeanerette and Cote Blanche Island. The Texas fields include Bego South and Briscoe Ranch. The Alabama field is Chunchula. As a result, the Company received sale proceeds of $48.8 million, net of $4.7 million in purchase price adjustments related to these properties. This sale also included the buyer's assumption of $27.7 million for asset retirement obligations on these properties.

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. This consideration was applied to 2010 activity.

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.

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.

Based upon quoted market prices as of December 31, 2011 and 2010, the fair value of our senior notes due 2017, was 254.8 million, or 101.9% of face value, and 254.7 million, or 101.9% of face value, respectfully. Based upon quoted market prices as of December 31, 2011 and 2010, the fair value of our senior notes due 2020, was $239.6 million, or 106.5% of face value and $242.3 million, or 107.7% of face value, respectively. Based upon quoted market prices as of December 31, 2011, the fair value of our senior notes due 2022, was 252.8 million, or 101.1% of face value. The carrying value of our senior notes due 2017 was $250.0 million at December 31, 2011 and 2010, while the carrying value of our senior notes due 2020 was $221.9 million and $221.6 million at December 31, 2011 and 2010, respectively, and the carrying value of our senior notes due 2022 was $247.9 million

The following tables present our assets that are measured at fair value as of December 31, 2011 and 2010. They 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):

	Fair Value Measurements at December 31,			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2011				
Oil Derivatives	$ 0.1	$ ---	$ 0.1	$ ---
2010				
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 notes due 2017, 2020 and 2022. The guarantees on our senior notes due 2017, 2020 and 2022 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, 2011				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated

ASSETS

Current assets	$---	$328,130	$21	$---	$ 328,151
Property and equipment	---	1,867,766	---	---	1,867,766
Investment in subsidiaries (equity method)	996,509	---	911,061	(1,907,570)	---
Other assets	---	16,552	85,429	(85,429)	16,552
Total assets	$996,509	$2,212,448	$996,511	$(1,992,999)	$ 2,212,469
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$211,792	$2	$---	$ 211,794
Long-term liabilities	---	1,089,595	---	(85,429)	1,004,166
Stockholders' equity	996,509	911,061	996,509	(1,907,570)	996,509
Total liabilities and stockholders' equity	$996,509	$2,212,448	$996,511	$(1,992,999)	$ 2,212,469

(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	$---	$158,335	$ 23	$ ---	$ 158,358
Property and equipment	---	1,572,845	---	---	1,572,845
Investment in subsidiaries (equity method)	880,017	---	808,780	(1,688,797)	---
Other assets	---	12,713	81,221	(81,221)	12,713
Total assets	$880,017	$1,743,893	$ 890,024	$(1,770,018)	$ 1,743,916
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$---	$146,728	$ 10,007	$ ---	$ 156,735
Long-term liabilities	---	788,385	---	(81,221)	707,164
Stockholders' equity	880,017	808,780	880,017	(1,688,797)	880,017
Total liabilities and stockholders' equity	$880,017	$1,743,893	$ 890,024	$(1,770,018)	$ 1,743,916

Condensed Consolidating Statements of Operations

(in thousands)	Year Ended December 31, 2011				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$---	$599,131	$ ---	$ ---	$ 599,131
Expenses	---	464,027	---	---	464,027
Income before the following:	---	135,104	---	---	135,104
Equity in net earnings of subsidiaries	98,821	---	84,610	(183,431)	---
Income from continuing operations, before income taxes	98,821	135,104	84,610	(183,431)	135,104
Income tax provision	---	50,494	---	---	50,494
Income from continuing operations	98,821	84,610	84,610	(183,431)	84,610
Income from discontinued operations, net of taxes	---	---	14,211	---	14,211
Net Income	98,821	84,610	98,821	$(183,431)	$ 98,821

(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)

Condensed Consolidating Statements of Cash Flow

(in thousands)	Year Ended December 31, 2011				
	Swift Energy Co. (Parent and Issuer)	Swift Energy Operating, LLC (Guarantor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$---	$373,058	$ 2	$ (4)	$ 373,056
Cash flow from investing activities	---	(450,048)	5,000	(5,000)	(450,048)
Cash flow from financing activities	---	242,321	(5,000)	5,000	242,321
Net increase in cash	---	165,331	2	(4)	165,329
Cash, beginning of period	---	86,346	21	---	86,367
Cash, end of period	$---	$251,677	$ 23	$ (4)	$ 251,696

(in thousands)	Year Ended December 31, 2010				
	Swift Energy Co.	Swift Energy	Other Subsidiaries	Eliminations	Swift Energy Co.

	(Parent and Issuer)	Operating, LLC (Guarantor)			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

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, 2011:		
Proved oil and gas properties	$	4,343,867
Unproved oil and gas properties		84,146
		4,428,013
Accumulated depreciation, depletion, and amortization		(2,574,370)
Net capitalized costs	$	1,853,643
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

Of the $84.1 million of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2011, excluded from the amortizable base, $26.4 million was incurred in 2011, $21.8 million was incurred in 2010, $13.9 million was incurred in 2009 and $22.0 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, 2011, 2010, and 2009.

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

	Year Ended December 31,					
		2011		2010		2009
Lease acquisitions and prospect costs1	$	52,779	$	60,641	$	61,105
Exploration		---		83,957		2,866
Development 2		540,714		276,024		111,095
Total acquisition, exploration, and development 3, 4	$	593,493	$	420,622	$	175,066

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 2011, 2010, and 2009 were $41.8 million, $50.3 million, and $56.8 million, respectively. Domestic costs for seismic data acquisition, included above, were $2.8 million, $6.1

million, and $4.4 million in 2011, 2010, and 2009, respectively.
2) Facility construction costs and capital costs have been included in development costs, and totaled $42.8 million, $29.9 million, and $18.4 million for the years ended December 31, 2011, 2010, and 2009, respectively.
3) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $29.3 million, $24.6 million, and $24.5 million in 2011, 2010, and 2009, respectively. In addition, the total includes $7.7 million, $7.4 million, and $6.1 million in 2011, 2010, and 2009, respectively, of capitalized interest on unproved properties.
4)Asset retirement obligations incurred, of approximately $20.7 million, $10.7 million and $12.5 million, have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2011, 2010, and 2009, respectively.

Results of Operations from continuing operations (in thousands).

	Year Ended December 31,		
	2011	2010	2009
Oil and gas sales	$ 602,341	$ 436,632	$ 371,749
Lease operating cost	(104,791)	(81,929)	(76,744)
Severance and other taxes	(52,508)	(45,868)	(41,326)
Depreciation, depletion, and amortization	(218,396)	(159,532)	(162,908)
Accretion of asset retirement obligation	(4,570)	(3,956)	(2,906)
Write-down of oil and gas properties	---	---	(79,312)
	222,076	145,347	8,553
Provision for income taxes	(83,056)	(54,505)	(3.378)
Results of producing activities	$ 139,020	$ 90,842	$ 5,175
Amortization per physical unit of production (equivalent Bbl of oil)	$ 20.75	$ 19.15	$ 17.99

These results of operations do not include the gains (losses) from our hedging activities of ($0.9) million, $0.7 million and ($1.4) million for 2011, 2010 and 2009, respectively. Our lease operating costs per Boe produced were $9.95 in 2011, $9.84 in 2010 and $8.47 in 2009.

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 domestic 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 94% of our 2011 domestic proved reserves, 98% of our 2010 domestic proved reserves and 96% of our domestic proved reserves for 2009.

Estimates of Proved Reserves	Total (Boe)	Natural Gas (Mcf)	Domestic Oil (Bbls)	NGL (Bbls)
Proved reserves as of December 31, 2008	116,440,458	292,379,957	49,684,917	18,025,548
Revisions of previous estimates1	(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 estimates1	(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 additions3	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
Revisions of previous estimates1	(4,657,802)	4,302,241	(3,294,117)	(2,080,725)
Purchases of minerals in place	---	---	---	---
Sales of minerals in place4	(16,049,309)	(64,765,392)	(3,876,295)	(1,378,782)
Extensions, discoveries, and other additions3	58,013,716	286,039,611	2,629,786	7,710,661

Production	(10,527,167)	(31,798,644)	(3,864,920)	(1,362,473)
Proved reserves as of December 31, 2011	159,561,788	616,759,607	30,931,512	25,837,008
Proved developed reserves: 2				
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
December 31, 2011	55,644,578	184,355,684	13,840,291	11,078,340

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, 2011, 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 2011, 2010 and 2009 did not materially affect prices used in these calculations. The 12-month 2011 average adjusted prices after differentials used in our calculations for domestic operations were $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL compared to 4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL for the 12-month average 2010 prices. The year-end 2009 prices used for domestic operations were $3.78 per Mcf of natural gas, $59.76 per barrel of oil, and $30.00 per barrel of NGL for domestic operations.

2) At December 31, 2011, 35% of our domestic reserves were proved developed, compared to 45% at December 31, 2010, and 50% at December 31, 2009.

3) We have added proved reserves primarily through our drilling activities, including 58.0 MMBoe added in 2011 and 36.7 MMBoe added in 2010. The 2011 proved reserves additions from drilling activities consisted almost entirely of reserves additions within our South Texas area, most of which were proved undeveloped additions based on the results of the horizontal drilling program conducted in this area during the year. 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.

4) In October 2011, we completed the disposition for our interests in six fields in South Louisiana, two in Texas and one in Alabama.

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, 2011	2010	2009
Future gross revenues	$ 6,895,214	$ 5,768,030	$ 4,358,412
Future production costs	(1,754,844)	(1,384,275)	(1,289,556)
Future development costs	(1,863,492)	(1,441,901)	(1,034,443)
Future net cash flows before income taxes	3,276,878	2,941,854	2,034,413
Future income taxes	(778,053)	(746,845)	(478,876)
Future net cash flows after income taxes	2,498,825	2,195,009	1,555,537
Discount at 10% per annum	(981,204)	(850,301)	(535,080)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 1,517,621	$ 1,344,708	$ 1,020,457

The standardized measure of discounted future net cash flows from production of proved reserves at year-end 2011 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 revenues 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 hedge activities at year-end 2011 consisted of price floor activity 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.

74

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

	Year Ended December 31, 2011	2010	2009
Beginning balance	$ 1,344,708	$ 1,020,457	$ 1,033,004
Revisions to reserves proved in prior years--			
Net changes in prices, net of production costs	283,310	501,997	149,000
Net changes in future development costs	(15,534)	(47,935)	(51,501)
Net changes due to revisions in quantity estimates	(105,438)	(186,180)	(53,094)
Accretion of discount	177,691	132,231	131,313
Other	61,676	(80,393)	(17,335)
Total revisions	401,705	319,720	158,383
New field discoveries and extensions, net of future production and development costs	103,983	325,561	40,447
Purchases of minerals in place	---	---	---
Sales of minerals in place	(172,870)	---	---
Sales of oil and gas produced, net of production costs	(445,043)	(308,834)	(253,683)
Previously estimated development costs incurred	252,931	118,147	64,033
Net change in income taxes	32,206	(130,343)	(21,727)
Net change in standardized measure of discounted future net cash flows	172,912	324,251	(12,547)
Ending balance	$ 1,517,620	$ 1,344,708	$ 1,020,457

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2011 and 2010 (in thousands, except per share data):

	Revenues	Income from Continuing Operations Before Taxes	Income from Continuing Operations	Gain (Loss) from Discontinued Operations	Basic EPS from Continuing Operations	Diluted EPS from Continuing Operations

2011:						
First	$144,078	$32,493	$20,249	$ (68)	$0.47	$0.47
Second	157,428	41,872	26,682	14,346	0.62	0.61
Third	142,532	27,395	17,007	(31)	0.39	0.39
Fourth	155,093	33,344	20,672	(36)	0.48	0.47
Total	$599,131	$135,104	84,610	$ 14,211	$1.96	$1.95
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

There were no extraordinary items in 2011 or 2010. Our New Zealand operations are accounted for as discontinued operations.

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income 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 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, 2011 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, 2011 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 8, 2012, 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 8, 2012, 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 8, 2012, 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 8, 2012, 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 8, 2012, 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, 2012, 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	Amendment No. 1 to the Company's Restated Certificate of Formation (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Form 8-K filed May16, 2011, File No. 1-08754).
3.3	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).
3.4	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	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).

4.2 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).

4.3 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).

4.4 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).

4.5 Second Supplemental Indenture dated as of November 30, 2011, among Swift Energy Company, Swift Energy Operating, LLC, and Wells Fargo Bank, National Association relating to the 7-7/8% Senior Notes due 2022 of Swift Energy Company (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 5, 2011, File No. 1-08754).

4.6 Registration Rights Agreement, dated November 30, 2011, by and among Swift Energy Company, Swift Energy Operating, LLC and J.P. Morgan Securities LLC, as representatives of the initial purchasers (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 5, 2011, File No. 1-08754).

4.7 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).

4.8 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).

4.9 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).

4.10 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).

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+	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).
10.5+	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).

10.6+	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).
10.7+	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).
10.8+	Amendment No. 4 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 16, 2011, File No. 1-08754).
10.9+	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).
10.10	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).
10.11	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).
10.12+	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).
10.13+	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).
10.14	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).
10.15	First Amendment and Consent to Second Amended and Restated Credit Agreement dated May 12, 2011, among Swift Energy Company, Swift Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference as Exhibit 10.01 to Swift Energy Company's Form 8-K filed May17, 2011, File No. 1-08754).
10.16	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).

10.17 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).

10.18+ 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).

10.19+ 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).

10.20+ 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).

10.21+ 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).

10.22+ 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).

10.23+ 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).

10.24+ 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).

10.25 Purchase Agreement, dated November 15, 2011 among the Company, the guarantor and J.P. Morgan Securities LLC, as representatives of the several initial purchasers (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed November 22, 2011, File No. 1-08745).

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 January 20, 2012.

* 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 23, 2012
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 23, 2012
/s/ Barry S. Turcotte Barry S. Turcotte	Vice-President Controller Principal Accounting Officer	February 23, 2012
/s/ Deanna L. Cannon Deanna L. Cannon	Director	February 23, 2012

/s/ Douglas J. Lanier Douglas J. Lanier	Director	February 23, 2012
/s/Greg Matiuk Greg Matiuk	Director	February 23, 2012
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	February 23, 2012
/s/ Charles J. Swindells Charles J. Swindells	Director	February 23, 2012
/s/ Bruce H. Vincent Bruce H. Vincent	Director	February 23, 2012