SWIFT ENERGY CO
Form 10-K
February 22, 2013

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, 2012

Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

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

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

Title of Class	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes	þ	No	o

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	o	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	o	No	þ

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.
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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 o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold on the New York Stock Exchange as of June 30, 2012, the last business day of June 2012, was approximately $778,385,135.

The number of shares of common stock outstanding as of January 31, 2013 was 43,002,344.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 21, 2013	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 21, 2013

Items 1 and 2. Business and Properties

See pages 27 and 28 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 December 31, 2012, we had estimated proved reserves of 192.1 MMBoe with a PV-10 Value of $2.3 billion (PV-10 Value 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). Our total proved reserves at December 31, 2012 were approximately 22% crude oil, 52% natural gas, and 26% NGLs while 34% of our total proved reserves were developed. Our proved reserves are concentrated with 82% in Texas and 18% 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

  Eagle Ford
  AWP
  Artesia Wells
  Fasken

- Southeast Louisiana
  Lake Washington
  Bay De Chene

- Central Louisiana / East Texas
  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 133.8 MMBoe to 192.1 MMBoe over the five-year period ended December 31, 2012. Over the same period, our annual production has grown from 10.6 MMBoe to 11.7 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our core areas. During 2012, 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 currently plan to fund our 2013 capital expenditures with our 2013 cash flow, cash on hand and potential line of credit borrowings. Our 2013 planned capital expenditures are $440 to $480 million focused on continued development of oil and liquid rich properties. The Company is also exploring joint venture arrangements for a portion of our Eagle Ford properties to accelerate drilling and development, monetize a portion of those asset values, diversify its risk profile and possibly free up capital dollars for other purposes. In addition, where appropriate we evaluate our properties for divestiture of assets that no longer optimally fit our strategy. Currently this includes our Brookeland field. For 2013, The Company is targeting production up to 3% over 2012 levels and proved reserves to increase 7% to 12% over year-end 2012 quantities with a focus on oil and liquid rich opportunities.

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. We have replaced 217% of our production on average over the last five years with our new reserves.

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, excluding taxes, were $9.87, $9.95 and $9.84 per Boe for the years ended December 31, 2012, 2011 and 2010, 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 94% of our proved oil and natural gas reserves base as of December 31, 2012. 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 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 2012 we completed 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 historical 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 50 MMBoe and still have remaining proved reserves of 12.5 MMBoe.

In October 2007, we acquired interests in two South Texas properties in the Gulf Coast basin which, along with AWP, have acreage in the Eagle Ford shale. 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, 2012, our debt to capitalization ratio was approximately 47%, while our debt to proved reserves was $4.77 per Boe, and our debt to PV-10 Value ratio was 40%. 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 72 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 six years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other related services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We increasingly use advanced technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, licensing and pre-stack time and depth imaging, advanced attributes, pore-pressure analysis, inversion and detailed field reservoir depletion planning. In 2012, we completed a project to invert, calibrate, merge and prestack time-migrate our 700 square miles of merged 3-D seismic data over and near our AWP field. As these data were updated 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 2012, we successfully drilled 55 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.

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Operating Areas (Continuing Operations)

The following table sets forth information regarding our 2012 year-end proved reserves from continuing operations of 192.1 MMBoe and production of 11.7 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
Artesia Wells - Eagle Ford	15.5	54.6	70.1	36.5 %	50.7 %	13.0 %	46.4 %
AWP - Eagle Ford	8.7	27.1	35.8	18.6 %	43.2 %	12.7 %	65.3 %
AWP - Olmos	17.3	13.0	30.3	15.8 %	42.1 %	26.8 %	42.5 %
Fasken - Eagle Ford	5.7	9.9	15.6	8.1 %	— %	18.5 %	— %
Other South Texas	4.8	—	4.8	2.6 %	47.7 %	2.1 %	45.2 %
Total South Texas	52.0	104.6	156.6	81.6 %		73.1 %	
Southeast Louisiana	7.9	7.1	15.0	7.8 %	84.9 %	19.0 %	86.3 %
Central Louisiana / East Texas	5.7	14.7	20.4	10.6 %	67.4 %	7.7 %	65.2 %
Other	0.1	—	0.1	— %	1.0 %	0.2 %	26.3 %
Total	65.7	126.4	192.1	100.0 %	48.1 %	100.0 %	48.2 %

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. During 2012 the Company drilled 22 wells in our AWP Eagle Ford field, of which three were joint venture wells. The Company owns a 51% working interest in these joint venture wells. These wells were all drilled and operated by Swift Energy. At December 31, 2012, we had identified 73 proved undeveloped locations. Our December 31, 2012 proved reserves in this formation are 57% natural gas, 25% NGLs, and 18% oil on a Boe basis. During 2013 we plan to drill approximately 10 wells targeting the AWP Eagle Ford field.

AWP - Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled nine horizontal Olmos wells in 2012. 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 58% natural gas, 30% NGLs, and 12% oil on a Boe basis. At December 31, 2012, we had 35 proved undeveloped locations in the Olmos. Our planned 2013 capital expenditures will include drilling approximately six horizontal wells targeting the Olmos formation.

Artesia Wells - Eagle Ford. During 2012 the Company drilled 22 operated wells in the Artesia Wells area. These wells were all operated and 100% owned by Swift Energy. Our December 31, 2012 proved reserves in this formation are 49% natural gas, 35% NGLs, and 16% oil on a Boe basis. At December 31, 2012, we had identified 84 proved undeveloped locations. During 2013 we plan to drill approximately 13 wells targeting the Artesia Wells area.

Fasken - Eagle Ford. During 2012 the Company drilled two operated wells in the Fasken Eagle Ford area. At December 31, 2012, we had identified 14 proved undeveloped locations. During 2013 we plan to drill two wells targeting the Fasken Eagle Ford area.

South Texas Acreage. As of December 31, 2012, we have 27,727 gross and 25,700 net developed acres and 64,542 gross and 50,192 net undeveloped acres in the Eagle Ford. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos we have 50,532 gross and 50,041 net developed acres and 52,893 gross and 48,919 net undeveloped acres. We have begun conducting downspacing tests to optimize the development of many of our Eagle Ford acreage positions.

Pursuit of Eagle Ford Joint Venture. We are currently exploring opportunities to enter into a joint venture arrangement with prospective partners in order to monetize our highest value acreage in our Eagle Ford properties, while at the same time creating opportunities to accelerate development of these properties in South Texas. Entering into a joint venture agreement would accelerate drilling and offer additional capital that we could deploy for our development program in other areas. We are targeting completion of this initiative by the third quarter of 2013.

Southeast Louisiana

Lake Washington. As of December 31, 2012, we owned drilling and production rights in 15,231 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 12.5 MMBoe in this field as of December 31, 2012, 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 2012 we drilled 10 development wells. In our production optimization program we performed 20 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At December 31, 2012, we had 53 proved undeveloped locations in this field. We will reduce our planned 2013 capital expenditures in the field but plan to drill three wells and perform recompletions on approximately 12 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, 2012, we owned drilling and production rights in approximately 14,253 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. During 2012, we drilled one well in the Bay De Chene field. At December 31, 2012, we had two proved undeveloped locations in the Bay de Chene field.

Central Louisiana/East Texas

Burr Ferry. The Company has 118,638 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 13,068 unleased acres, primarily in our Burr Ferry field. During 2012, the Company drilled four non-operated wells and one operated well in this joint venture. The reserves are approximately 66% oil and NGLs. We have identified 18 additional proved undeveloped locations in this field. In 2013, we plan to drill approximately three wells.

Masters Creek. As of December 31, 2012, we owned drilling and production rights in 37,458 net acres in the Masters Creek field. The Masters Creek field is located in Vernon Parish and Rapides Parish, Louisiana. Oil and natural gas 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 December 31, 2012, we had six proved undeveloped locations. During 2012 we did not drill any wells 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, 2012, we owned drilling and production rights in 5,901 net acres in this field. Wells drilled in this field are completed in a multiple set of separate sands in the Wilcox formation. In 2012, we did not drill any wells in this field. At December 31, 2012 we had 18 proved undeveloped locations in this field. During 2013, we plan to drill one oil test infill well in this area using horizontal drilling and multi-stage hydraulic fracturing technologies.

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 December 31, 2012, we had approximately 51,428 net acres leased in the Four Corners area of southwest Colorado. This high quality, cost effective and meaningful acreage position prospective for shallow, oil-rich, Niobrara production, is primarily in La Plata County, Colorado. In 2013, we plan to drill an exploratory well in this area later in the year, and have already conducted detailed analysis of the basin, production history and other current activity in the 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, 2012, 2011 and 2010. The information set forth in the tables regarding reserves is based on proved reserves reports we have prepared. Our Chief Reserves Engineer, 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 96%, 94% and 98% of our domestic proved reserves for the years ended December 31, 2012, 2011 and 2010. 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 30 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 Chief Reserves Engineer 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 reserves audit report and the overall reserves 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, 2012, 2011 and 2010 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 following prices are used to estimate our year-end PV-10 Value. The 12-month 2012 average adjusted prices after differentials for domestic operations were $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL, compared to $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL at year-end 2011 and $4.08 per Mcf of natural gas, $78.31 per barrel of oil, and $42.01 per barrel of NGL at year-end 2010.

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, 2012, 2011 and 2010. 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 (the "Standardized Measure"), which is calculated after provision for future income taxes. The following amounts shown in MBoe below are based on a natural gas conversion factor of 6 Mcf to 1 Boe:

Estimated Proved Oil, NGL and Natural Gas Reserves	As of December 31,		
	2012	2011	2010
Natural gas reserves (MMcf):			
Proved developed	195,643	184,355	190,454
Proved undeveloped	401,926	432,404	232,528
Total	597,569	616,759	422,982
Oil reserves (MBbl):			
Proved developed	17,780	13,840	16,782
Proved undeveloped	25,479	17,091	22,555
Total	43,259	30,931	39,337
NGL reserves (MBbl):			
Proved developed	15,328	11,078	11,874
Proved undeveloped	33,891	14,759	11,074
Total	49,219	25,837	22,948
Total Estimated Reserves (MBoe)	192,073	159,562	132,782
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$1,201	$1,075	$976
Proved undeveloped	1,083	843	801
PV-10 Value	$2,284	$1,918	$1,777

The PV-10 Values for the years ended December 31, 2012, 2011 and 2010 are net of $89.6 million, $75.0 million, and $82.3 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.

PV-10 Value is a non-GAAP measure. The closest GAAP measure to the PV-10 Value is the Standardized Measure. We believe the PV-10 Value is a useful supplemental disclosure to the Standardized Measure because the PV-10 Value is a widely used measure within the industry and is commonly used by securities analysts, banks and credit rating agencies to evaluate the value of proved reserves on a comparative basis across companies or specific properties. We use the PV-10 Value in our ceiling test computations, for comparison against our debt balances, to evaluate properties that are bought and sold and to assess the potential return on investment in our oil and gas properties. PV-10 Value is not a measure of financial or operating performance under GAAP, nor should it be considered in isolation or as a substitute for the Standardized Measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves. The following table provides a reconciliation between the PV-10 Value and the Standardized Measure.

	As of December 31,		
(in millions)	2012	2011	2010
PV-10 Value	$2,284	$1,918	$1,777
Future income taxes (discounted at 10%)	(412)	(400)	(432)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$1,872	$1,518	$1,345

Domestic Proved Undeveloped Reserves

The following table sets forth the aging of our domestic proved undeveloped reserves as of December 31, 2012:

Year Added	Volume (MMBoe)	% of PUD Volumes
2012	68.9	55 %
2011	34.5	27 %
2010	15.0	12 %
2009	2.8	2 %
2008	2.8	2 %
Prior to 2008	2.4	2 %
Total	126.4	100 %

During 2012, we recorded 33.2 MMBoe of additional proved undeveloped reserves based on the results of the drilling program conducted during the year in the Artesia Wells and Burr Ferry fields. Additional changes included performance-related additions of 22.8 MMBoe in proved undeveloped reserves in the liquids rich Artesia Wells field, largely offset by reductions of 19.1 MMBoe in proved undeveloped reserves in the Fasken field due to low natural gas prices. We also spent approximately $135 million in capital expenditures during the year to convert 7.3 MMBoe of our December 31, 2011 proved undeveloped reserves to proved developed reserves, primarily in the Artesia Wells field.

The PV-10 Value from our proved undeveloped reserves was $1.1 billion at December 31, 2012 which was approximately 47% of our total PV-10 Value of $2.3 billion. The PV-10 Value of our proved undeveloped reserves, by year of booking, was 66% in 2012, 3% in 2011, 15% in 2010, less than 1% in 2009, 8% in 2008 and 8% prior to 2008.

Sensitivity of Domestic Reserves to Pricing

As of December 31, 2012, a 5% increase in oil and NGL pricing would increase our total estimated domestic proved reserves of 192.1 MMBoe by approximately 0.5 MMBoe, and would increase the PV-10 Value of $2.3 billion by approximately $174 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated domestic proved reserves by approximately 0.7 MMBoe and would decrease the PV-10 Value by approximately $173 million.

As of December 31, 2012, a 5% increase in natural gas pricing would increase our total estimated domestic proved reserves by approximately 0.3 MMBoe and would increase the PV-10 Value by approximately $43 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated domestic proved reserves by approximately 0.3 MMBoe and would decrease the PV-10 Value by approximately $42 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, 2012			
Gross	375	744	1,119
Net	345.9	713.5	1,059.4
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	1,214.9

(1) Excludes 59, 38 and 58 service wells added in 2012, 2011 and 2010.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2012:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	—	—	73,616	51,428
Louisiana (1)	144,408	125,824	128,388	78,899
Texas (2)	135,866	113,730	47,542	42,183
Wyoming	—	—	10,390	8,174
Total	280,274	239,554	259,936	180,684

(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 50,777 net developed mineral acres and 23,998 net undeveloped mineral acres. The Company also owns fee mineral interests in approximately 13,068 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 27,727 gross and 25,700 net developed acres and 64,542 gross and 50,192 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos, we have 50,532 gross and 50,041 net developed acres and 52,893 gross and 48,919 net undeveloped acres.

As of December 31, 2012, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 12% in 2013, 7% in 2014 and 6% in 2015. 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 years ended December 31, 2012, 2011 and 2010:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2012	Exploratory	—	—	—	—	—	—
	Development	71	71	—	66.2	66.2	—
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

Present Activities

As of December 31, 2012, we were in the process of drilling two wells in our South Texas Area, in which we own a 100% working interest, and one well in the Burr Ferry field, in which we own a 50% working interest. We have also continued the production optimization program in the Lake Washington field to mitigate natural field declines, involving recompletions, stimulations, 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 2012 totaled $11.3 million and ranged from $374 to $2,934 per well per month.

Fixed and Determinable Commitments

As of December 31, 2012, we had natural gas sales commitments to deliver fixed and determinable quantities of natural gas under term contracts as follows:

Year	Delivery Quantity (MMBTU)
2013	—
2014	7,650,000
2015	6,680,000

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. For the years ended December 31, 2012, 2011 and 2010, Shell Oil Company and affiliates accounted for 46%, 49% and 52% of our total oil and gas gross receipts, respectively. Southcross Energy accounted for approximately 11% of our total oil and gas gross receipts in 2012, while 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). Historically, 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 (the segment of line into which Swift delivers its gas was sold to High Point Energy, LLC in 2012) 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 Texas Pipeline and Enterprise Hydrocarbons. The processed natural gas liquids are sold to Southcross. The residue gas is sold at prevailing prices to Southcross and other parties at downstream connections on Southcross' system. Other gas production in the AWP area is processed or transported under arrangements with Houston Pipe Line, 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 natural gas 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. The Meritage pipeline was sold to Howard Energy in 2012.

In 2012, we entered into an agreement with Eagle Ford Gathering LLC that provides for the gathering and processing for almost all of our natural gas production in the Artesia Wells area. The processed natural gas liquids are purchased by Eagle Ford Gathering. The residue gas is sold to various parties at prevailing market prices at connections downstream of the processing facilities. For natural gas deliveries to Enterprise, Enterprise purchases the processed liquids when processing is available, with the residue gas sold at prevailing market prices. In the Artesia Wells area, our oil production is sold at prevailing market prices and transported to market by truck.

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 NGLs in the gas stream prior to delivery to Trunkline. Those NGLs 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 prices in the tables below 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 summarizes sales volumes, sales prices, and production cost information for our net oil, NGL and natural gas production from our continuing operations for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31,		
All Fields	2012	2011	2010
Net Sales Volume:			
Oil (MBbls)	3,774	3,865	3,905
Natural Gas Liquids (MBbls)	1,862	1,362	1,138
Natural gas (MMcf) (1)	32,862	29,901	17,832
Total (MBoe)	11,113	10,211	8,015
Average Sales Price:			
Oil (Per Bbl)	$ 106.17	$ 107.00	$ 79.45
Natural Gas Liquids (Per Bbl)	$ 35.07	$ 52.13	$ 42.44
Natural gas (Per Mcf)	$ 2.68	$ 3.94	$ 4.38
Average Production Cost (Per Boe sold) (2)	$ 10.39	$ 10.26	$ 10.22

(1) Excludes gas consumed in operations that is included in reported production volumes of 3,524 MMcf in 2012, 1,898 MMcf in 2011 and 1,889 MMcf in 2010.
(2) Excludes severance and ad valorem taxes.

The following table provides a summary of our sales volumes, average sales prices, and average production costs for our Artesia Wells, AWP Eagle Ford and AWP Olmos fields in South Texas. These fields account for approximately 71% of the Company's proved reserves based on total Boe as of December 31, 2012:

	Year Ended December 31,		
Artesia Wells	2012	2011	2010
Net Sales Volume:			
Oil (MBbls)	301	22	1
Natural Gas Liquids (MBbls)	406	37	7
Natural gas (MMcf) (1)	4,733	469	51
Total (MBoe)	1,496	137	17
Average Sales Price:			
Oil (Per Bbl)	$ 98.54	$ 87.15	$ 81.43
Natural Gas Liquids (Per Bbl)	$ 32.93	$ 54.49	$ 48.91
Natural gas (Per Mcf)	$ 3.07	$ 3.70	$ 3.76
Average Production Cost (Per Boe sold) (2)	$ 4.16	$ 7.32	$ 3.83

(1) Excludes gas consumed in operations that is included in reported production volumes of 152 MMcf in 2012.
(2) Excludes severance and ad valorem taxes.

AWP Eagle Ford	Year Ended December 31, 2012	2011	2010
Net Sales Volume:			
Oil (MBbls)	677	400	155
Natural Gas Liquids (MBbls)	296	173	34
Natural gas (MMcf) (1)	3,004	3,163	967
Total (MBoe)	1,474	1,100	350
Average Sales Price:			
Oil (Per Bbl)	$ 101.57	$ 96.36	76.96
Natural Gas Liquids (Per Bbl)	$ 36.53	$ 49.84	37.89
Natural gas (Per Mcf)	$ 2.73	$ 4.04	4.08
Average Production Cost (Per Boe sold) (2)	$ 6.43	$ 6.92	3.00

(1) Excludes gas consumed in operations that is included in reported production volumes of 98 MMcf in 2012, 48 MMcf in 2011 and one MMcf in 2010.
(2) Excludes severance and ad valorem taxes.

AWP Olmos	Year Ended December 31, 2012	2011	2010
Net Sales Volume:			
Oil (MBbls)	490	376	256
Natural Gas Liquids (MBbls)	843	644	590
Natural gas (MMcf) (1)	9,865	10,531	7,392
Total (MBoe)	2,977	2,775	2,078
Average Sales Price:			
Oil (Per Bbl)	$ 102.26	$ 95.36	$ 76.88
Natural Gas Liquids (Per Bbl)	$ 33.89	$ 50.49	$ 40.52
Natural gas (Per Mcf)	$ 2.55	$ 3.98	$ 4.40
Average Production Cost (Per Boe sold) (2)	$ 10.46	$ 9.53	$ 7.53

(1) Excludes gas consumed in operations that is included in reported production volumes of 935 MMcf in 2012, 232 MMcf in 2011 and 235 MMcf in 2010.
(2) Excludes severance and ad valorem taxes.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or individual injuries. The oil and natural gas exploration business is also subject to environmental hazards, such as oil spills, natural gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. See “1A. Risk Factors” of this report for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance, operators extra expense insurance, and property damage insurance. Our standing Insurable Risk Adviser 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, 2012, we did not have any outstanding derivative instruments in place for future production.

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, 2012, we employed 332 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2012, 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 $485,000 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 the Principal Executive Officers. 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 (particularly those in major oil producing regions, especially the Middle East). Thus far in 2013, there have been further declines in natural gas futures and spot prices. For example, the NYMEX January 2013 natural gas contracts settled at $3.35 per MMBtu and for February 2013 at $3.23 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 either oil or gas would negatively affect us in several ways, including:

- 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;
- such a reduction may result in a downward adjustment to our estimated proved reserves, and require write-downs of our properties; 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.

We have previously incurred write-downs 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. Unescalated prices are calculated under these accounting rules using a 12-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. If oil and gas prices decline in the future, subject to the degree to which we incur additional capital costs on oil and gas properties and add proved reserves, we may be required to record write-downs of our oil and gas properties in subsequent periods.

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 our capital expenditures are limited to funding from our cash flow in lower commodity price environments, or 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.

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 an area in which we have been affected by constraints for periods of time. 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.

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, 2012, approximately 66% 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 8% of our 2012 reserves and 19% of our 2012 production are located in our Southeast Louisiana core areas. Increased hurricane activity over the past five years has 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, by Hurricanes Gustav and Ike in 2008, and by Hurricane Isaac in 2012. 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 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 2012 we extended our line of credit through November 2017 and although we had an outstanding balance under that line of credit as of December 31, 2012 of $39.4 million, 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.

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, 2012, our total debt comprised approximately 47% 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.

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.

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.

From time to time 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 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.

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.

Final rules regulating air emissions from natural gas production could cause us to incur increased capital expenditures and operating costs, which could be significant.

On August 16, 2012, the U.S. Environmental Protection Agency ("EPA") published final regulations under the federal Clean Air Act that require additional emission controls for natural gas production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require, among other things, the reduction of VOC emissions from storage vessels and certain fractured and refractured gas wells for which well completion operations are conducted. Under the rule, after October 15, 2012, flowback emissions must be routed to a gathering line or be captured or flared, and the new emission standards for storage vessels go into effect on October 15, 2013. Reduced emission completions, also known as “green completions,” are not required until January 1, 2015. Petitions for reconsideration of the rule already have been filed with the EPA and legal challenges have been filed which could delay or result in changes to the rule. We are currently reviewing this new rule to assess its potential impact on our operations. Compliance with these requirements may significantly increase our costs of development and production.

Additionally, 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.

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. 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. 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.

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.

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, the American Recovery and Reinvestment Act of 2009, and the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the “Dodd-Frank Act”), 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.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain U.S. federal income tax benefits and deductions currently available to oil and gas companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the increase of the amortization period of geological and geophysical expenses, (iii) the elimination of current deductions for intangible drilling and development costs; and (iv) the elimination of the deduction for certain U.S. production activities. It is unclear whether any such proposals will be enacted or what form they might possibly take. The passage of such legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The Dodd-Frank Act requires the Commodities Futures Trading Commission, referred to as the CFTC, and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. These new rules and regulations could (i) significantly increase the cost of derivative contracts (including those requirements to post collateral, which could adversely affect our available liquidity); (ii) reduce the availability of derivatives to protect against risks we encounter; and (iii) reduce the liquidity of energy related derivatives. Although we believe the derivative contracts that we enter into should not be materially impacted by position limits, clearing and collateral requirements and other regulatory requirements, the impact upon our businesses will depend on whether the derivative contracts we enter into are exempt from position limits as bona fide hedging transactions and from clearing and collateral requirements based on the exception for commercial end-users.

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 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]
Standardized Measure - The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and natural gas operations. Sales prices were prepared using average hydrocarbon prices equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period preceding the reporting date (except for consideration of price changes to the extent provided by contractual arrangements).

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. Mine Safety Disclosures

None.

PART II

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

Common Stock, 2012 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 2012 and 2011 were as follows:

	2012				2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$28.30	$15.09	$17.25	$14.28	$38.32	$33.07	$24.34	$21.81
High	$35.00	$30.44	$23.10	$21.07	$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 163 stockholders of record as of December 31, 2012.

Stock Repurchase Table

The following table summarizes repurchases of our common stock occurring during the fourth quarter of 2012:

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)
10/01/12 - 10/31/12 (1)	332	$ 17.89	—	$---
11/01/12 - 11/30/12 (1)	746	$ 15.51	—	—
12/01/12 - 12/31/12 (1)	431	$ 15.62	—	—
Total	1,509	$ 16.06	—	$---

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

Equity Compensation Plan Information

The 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, 2012 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 (annual data in thousands except share & well amounts)	2012	2011	2010	2009	2008
Total Revenues from Continuing Operations (1)	$557,290	$599,131	$438,429	$370,445	$820,815
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$36,578	$135,104	$74,308	$(64,617)	$(412,758)
Income (Loss) from Continuing Operations (1)	$20,939	$84,610	$46,475	$(39,076)	$(257,130)
Net Cash Provided by Operating Activities - Continuing Operations	$314,606	$373,058	$258,996	$226,176	$582,027
Per Share and Share Data					
Weighted Average Shares Outstanding(1)	42,840	42,394	38,300	33,594	30,661
Earnings per Share--Basic(1)	$0.48	$1.96	$1.19	$(1.16)	$(8.39)
Earnings per Share--Diluted(1)	$0.48	$1.95	$1.18	$(1.16)	$(8.39)
Shares Outstanding at Year-End	42,930	42,485	41,999	37,457	30,869
Book Value per Share at Year-End	$24.15	$23.46	$20.95	$18.12	$19.47
Market Price					
High	$35.00	$47.32	$40.83	$25.61	$67.03
Low	$14.28	$21.81	$24.52	$4.95	$15.30
Year-End Close	$15.39	$29.72	$39.15	$23.96	$16.81
Assets					
Current Assets	$80,537	$332,119	$158,358	$108,600	$78,086
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$2,345,020	$1,867,766	$1,572,845	$1,315,964	$1,431,447
Total Assets	$2,444,061	$2,216,437	$1,743,916	$1,434,765	$1,517,288
Liabilities					
Current Liabilities	$177,480	$215,762	$156,735	$103,604	$153,499
Long-Term Debt	$916,934	$719,775	$471,624	$471,397	$580,700
Total Liabilities	$1,407,201	$1,219,928	$863,899	$755,866	$916,411
Stockholders' Equity	$1,036,860	$996,509	$880,017	$678,899	$600,877
Number of Domestic Employees	332	309	292	295	334
Domestic Producing Wells					
Swift Operated	1,069	1,025	1,212	1,146	1,168
Outside Operated	50	46	119	148	159
Total Domestic Producing Wells	1,119	1,071	1,331	1,294	1,327
Domestic Wells Drilled (Gross)	71	44	56	20	126
Domestic Proved Reserves					
Natural Gas (Bcf)	597.6	616.8	423.0	290.6	292.4
Oil Reserves (MBoe)	43.3	30.9	39.3	44.5	49.7

NGL Reserves (MBoe)	49.2	25.8	23.0	20.0	18.0
Total Domestic Proved Reserves (MMBoe equivalent)	192.1	159.6	132.8	112.9	116.4
Domestic Production (MMBoe equivalent)	11.7	10.5	8.3	9.1	10.0
Domestic Average Sales Price (2)					
Natural Gas (per Mcf produced)	$2.42	$3.70	$3.96	$3.48	$8.54
Natural Gas Liquids (per barrel)	$35.07	$52.13	$42.44	$31.36	$57.15
Oil (per barrel)	$106.17	$107.00	$79.45	$60.07	$101.38
Boe Equivalent	$47.37	$57.22	$52.42	$41.05	$79.00

(1) Amounts have been retroactively adjusted in all periods presented to give recognition to discontinued operations related to the sale of our New Zealand oil & gas assets.

(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.

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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, 2012, 2011 and 2010 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 39 of this report.

Overview

We are an independent oil and natural gas company formed in 1979 and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development. Oil production accounted for 32% of our 2012 production and 72% of our oil and gas sales, and combined production of both oil and natural gas liquids (“NGLs”) constituted 48% of our 2012 production and 84% of our oil and gas sales. This has allowed us to benefit from better margins for oil production, as oil prices are significantly higher on a Boe basis than natural gas prices.

2012 Activities

- Production: Our production volumes increased by 11% in 2012 when compared to volumes in 2011 as NGL volumes increased by 37% and natural gas production volumes increased by 14%, while oil volumes decreased by 2%. The increase in NGL and natural gas production came from our South Texas area. Although the percentage of our total production volumes from crude oil sales has steadily decreased over the last three years, crude oil sales as a percentage of our total oil and gas sales have remained relatively stable.
- Increased Reserves: Our year-end 2012 total proved reserves increased over our year-end 2011 reserves by 20% to a Company record of 192.1 MMboe, while our oil and NGLs as a percentage of total reserves increased to 48% in 2012 from 36% in 2011. This increase was mainly due to large increases in oil and NGL reserves in our South Texas area.
- Pricing: Our weighted average sales price in 2012 decreased 17% when compared to levels in 2011 as natural gas prices declined 35%, NGL prices declined 33% and oil prices declined 1%.
- Cash provided by operating activities: Decreased by $58.5 million or 16%, when compared to 2011, due to the decline in prices received during the period.
- Revenues and Earnings: Our oil and gas sales of $554.2 million declined 8% in 2012 when compared to levels in 2011, due to the decrease in natural gas and NGL prices discussed above. When combined with an increase in total costs and expenses of $56.7 million or 12%, and $14.2 million of income from discontinued operations recognized in 2011, our 2012 net income fell 79% to $20.9 million.
- 2012 debt issuance and available liquidity: In October 2012, we issued $150.0 million of 7.875% senior notes due 2022 at a premium of $7.5 million which equates to an effective yield of 7%. These notes were an add-on to the original $250.0 million of 7.875% senior notes due 2022 that were issued in November 2011. We also extended our credit facility through 2017 and increased the borrowing base and commitment amount to $450.0 million.
- 2012 capital expenditures: Our capital expenditures on a cash flow basis were $757.8 million in 2012 compared to $505.3 million spent in 2011. The increase of $252.4 million was mainly due to additional drilling and completion activity during 2012 in our South Texas core region as we drilled 22 wells in our Artesia Wells Eagle Ford field, 22 wells in our AWP Eagle Ford field, nine wells in our AWP Olmos field and two wells in our Fasken Eagle Ford field, which helped us evaluate Eagle Ford and Olmos acreage positions in those areas. We also drilled 11 wells in our Southeast Louisiana area and five wells in our Central Louisiana/East Texas area, including four non-operated wells. These 2012 expenditures were primarily funded by $314.6 million of cash provided by operating activities, the

remaining cash proceeds from our 2011 and 2012 note issuances and our credit facility.

- 2012 operating efficiencies: Our South Texas drilling activities have benefited from optimized well design, improved operational efficiencies, and applied lessons learned from our experience in this area, all of which have resulted in a reduction of drilling days per well. Consequently, we are currently able to drill more wells per rig than previously expected. We have also experienced efficiency gains in our hydraulic fracturing activities which enables us to perform more frac stages per month and lower the overall frac cost per stage.

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2013 Strategy and Outlook

- Focus on oil and liquids properties with expanded capital budget: Our inventory of drilling locations allows us to be flexible in scheduling upcoming wells in South Texas to focus on oil and natural gas liquids. Having fulfilled our near-term obligations on most of our acreage prospective for dry natural gas production, we are concentrating on our higher return, liquids rich acreage almost exclusively in 2013. Our 2013 capital expenditures are currently estimated to be $440 to $480 million focused on continued development of oil and liquid rich properties. We plan to fund these expenditures through operating cash flow, availability under our credit facility and potential non-core property dispositions.
- Increase reserves with stable production: For 2013, The Company is targeting production up to 3% over 2012 levels and proved reserves to increase 7% to 12%, over year-end 2012 quantities with a focus on oil and liquid rich opportunities.
- Added midstream capacity and securing transportation capacity: Additional dedicated transportation and processing through a newly constructed third-party pipeline of a midstream provider (handling natural gas production from our AWP Eagle Ford and Olmos areas) became operational at the beginning of October 2011. In our Fasken area, we also secured capacity on a pipeline built in late 2010 by a midstream provider, and in both the AWP and Fasken areas we have secondary transportation outlets available if capacity is restricted on our primary outlets. In June 2012, we entered into an agreement for natural gas gathering and processing for our Artesia Wells Eagle Ford field.
- Capital cost saving measures: We have realized significant capital cost savings in South Texas related to pad drilling, well construction & completion re-design, sourcing & 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 2013 program execution.
- Strategic Growth Initiatives: During 2013, the Company intends to devote 5% to 10% of its budget to strategic growth initiatives in Louisiana, including a horizontal well to test the Wilcox formation in our South Bearhead Creek field and a well to test the Niobrara oil formation in La Plata County, Colorado.
- Prospective Joint Venture: In order to leverage the number of wells that can be drilled and our pace of drilling, the Company is currently exploring opportunities to create a joint venture covering portions of the Company's highest value acreage in the Eagle Ford shale.

2013 Known Trends and Uncertainties Affecting our Business

- Flattened production and cash flows: In 2013, we plan to reduce our capital expenditures by approximately 30% to 40% from 2012 levels, in order to live within the limits of reduced cash flow. This is due to a lower commodity price environment, increased water production in Lake Washington leading to reduced anticipated base production during 2013, and the dedication of up to 25% of the year's budget to long-term strategic initiatives, facilities, gathering systems and other infrastructure.
- Recent declines in natural gas and natural gas liquids 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 through 2012, with noted improvement in the later half of 2012. Natural gas liquids prices have also declined recently due to many of the same reasons that natural gas prices have declined. Lower natural gas and natural gas liquids prices equate to lower revenue and cash flows and might lead to reductions in our borrowing capacity. As natural gas makes up 52% of our reserves base on a Boe basis, lower natural gas prices in the future could lead to potential reserves reductions which could result in full-cost ceiling write-downs.
- 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 area, 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. In South Texas we have seen improvement in the availability of services as additional equipment has moved into this area.
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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.

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Results of Operations

Revenues — Years Ended December 31, 2012, 2011 and 2010

2012 - Our revenues in 2012 decreased by 7% compared to revenues in 2011, due to lower NGL and natural gas pricing, partially offset by higher natural gas and NGL production. Average oil prices we received were 1% lower than those received during 2011, while natural gas prices were 35% lower, and NGL prices were 33% lower.

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 we received were 35% higher than those received during 2010, while natural gas prices were 6% lower, and NGL prices were 23% higher.

Crude oil production was 32%, 37% and 47% of our production volumes in the years ended December 31, 2012, 2011 and 2010, respectively. Crude oil sales were 72%, 69% and 71% of oil and gas sales in the years ended December 31, 2012, 2011 and 2010, respectively. Natural gas production was 52%, 50% and 39% of our production volumes in the years ended December 31, 2012, 2011 and 2010, respectively. Natural gas sales were 16%, 20% and 18% of oil and gas sales in the years ended December 31, 2012, 2011 and 2010, respectively. The remaining production in each year was from NGLs.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2012, 2011 and 2010:

Core Regions	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2012	2011	2010	2012	2011	2010
Southeast Louisiana	$ 212.1	$ 287.6	$ 246.2	2,227	3,164	3,706
South Texas	288.2	225.3	120.4	8,555	5,937	3,235
Central Louisiana / East Texas	53.2	86.8	67.4	898	1,375	1,329
Other	0.7	2.6	2.6	20	51	60
Total	$ 554.2	$ 602.3	$ 436.6	11,700	10,527	8,330

In 2012, our $48.1 million, or 8% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $81.4 million unfavorable impact on sales, with a decrease of $46.5 million attributable to the 35% decrease in natural gas prices, a decrease of $31.8 million due to the 33% decrease in NGL prices and a decrease of $3.1 million due to the 1% decrease in oil prices received,
- Volume variances that had a $33.3 million favorable impact on sales, with a $26.0 million increase attributable to the 0.5 million Bbl increase in NGL production volumes and a $17.0 million increase due to the 4.6 Bcf increase in natural gas production volumes, partially offset by a $9.7 million decrease due to the 0.1 million Bbl decrease in oil production volumes.

In 2011, our $165.7 million, or 38% 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 $47.8 million of increase attributable to the 12.1 Bcf increase in natural gas production volumes, $9.5 million of increase attributable to the 0.2 million Bbl increase in NGL production volumes, reduced by $3.2 million of decreases attributable to the 0.04 million Bbl decrease in oil production volumes.

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The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, by quarter, for the years ended December 31, 2012, 2011 and 2010:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2010							
First Quarter	945	303	4.8	2,045	$78.10	$44.71	$4.74
Second Quarter	979	279	4.6	2,028	$77.83	$41.92	$3.72
Third Quarter	1,005	256	4.9	2,072	$76.39	$39.88	$3.87
Fourth Quarter	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 Quarter	985	348	7.9	2,646	$98.61	$48.87	$3.82
Second Quarter	994	335	7.9	2,641	$112.09	$50.41	$3.93
Third Quarter	937	247	8.1	2,542	$105.55	$57.76	$3.68
Fourth Quarter	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
2012							
First Quarter	884	376	9.2	2,799	$111.99	$45.30	$2.18
Second Quarter	905	430	9.5	2,918	$108.02	$35.25	$2.01
Third Quarter	870	512	9.0	2,875	$102.73	$31.29	$2.52
Fourth Quarter	1,115	544	8.7	3,108	$102.73	$31.42	$3.04
Total	3,774	1,862	36.4	11,700	$106.17	$35.07	$2.42

For the years ended December 31, 2012, 2011 and 2010, we recorded net gains (losses) of $2.3 million, ($0.9) million and $0.7 million, respectively, related to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $106.77, $106.81 and $79.52 for the years ended December 31, 2012, 2011 and 2010, respectively, and our average natural gas price would have been $2.42, $3.70 and $3.98 for the years ended December 31, 2012, 2011 and 2010, respectively.

Costs and Expenses

Our expenses for the year ended December 31, 2012 increased $56.7 million, or 12%, compared to the prior year levels, for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $10.7 million, or 10%, compared to the level of such expenses for the year ended December 31, 2011, due to higher workover costs in Southeast Louisiana and additional costs in our South Texas region for transportation, salt water disposal and chemical treating. Our lease operating costs per Boe produced, however were $9.87 and $9.95 for the years ended December 31, 2012 and 2011, respectively, due to higher production volumes.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $25.9 million, or 12%, from those during the year ended December 31, 2011, due to a higher depletable base (including higher future development costs and higher production volumes), partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $21.13 and $21.02 for the years ended December 31, 2012 and 2011, respectively, resulting from increases in the per unit cost of reserves additions in 2012.

General and Administrative Expenses, Net. These expenses increased $1.4 million, or 3%, compared to the level of such expenses for the year ended December 31, 2011. The increase was primarily due to higher salaries and burdens, partially offset by a lower corporate benefit accrual. For the years ended December 31, 2012 and 2011, our capitalized general and administrative costs totaled $31.1 million and $29.3 million, respectively. Our net general and administrative expenses per Boe produced were $4.00 and $4.31 for the years ended December 31, 2012 and 2011, respectively. The supervision fees recorded as a reduction to general and administrative expenses were $11.3 million and $12.9 million for the years ended December 31, 2012 and 2011, respectively.

Severance and Other Taxes. These expenses decreased $3.6 million, or 7%, from the year ended December 31, 2011. Severance and other taxes, as a percentage of oil and gas sales, were approximately 8.8% and 8.7% for the years ended December 31, 2012 and 2011, respectively.

Interest. Our gross interest cost for the year ended December 31, 2012 was $65.2 million, of which $7.9 million was capitalized. Our gross interest cost for the year ended December 31, 2011 was $43.2 million, of which $7.7 million was capitalized. The increase in interest came from the $250.0 million issuance of our senior notes due 2022 in November 2011 and the additional $150.0 million issuance of our senior notes due 2022 in October 2012.

Income Taxes. Our effective income tax rate was 42.8% and 37.4% for the years ended December 31, 2012 and 2011, respectively. The increase was due to an increase in the ratio of non-deductible expenses to net income, along with an increase in provision for state taxes, partially offset by a favorable adjustment to reverse a liability for an uncertain tax position for which the statutory audit period expired.

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 thus 100% of the Company's oil and gas operations were in the United States of America.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the year ended December 31, 2012, our net cash provided by operating activities was $314.6 million, representing a 16% decrease compared to $373.1 million generated during 2011. The $58.5 million change was mainly due to the decline in commodity prices received during the year.

Existing Credit Facility. After the regularly scheduled review of our credit facility on October 31, 2012, the Company's borrowing base and commitment amount were increased to $450.0 million from the previous borrowing base and commitment amounts of $375.0 million and $300.0 million, respectively. The maturity of the credit facility was also extended to November 1, 2017 from May 12, 2016. At December 31, 2012, we had $39.4 million in outstanding borrowings under our credit facility. 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.

2012 Debt Issuance. On October 3, 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022. The notes were issued at 105% of par, which equates to a yield to worst of 6.993%. The proceeds from this debt issuance were used to pay down the balance on our credit facility, which increased our available liquidity.

2011 Debt Issuance. We issued $250.0 million of 7.875% senior notes due in 2022 in November 2011 at 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 were used to fund capital expenditures in 2012.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of $116.4 million at December 31, 2011, to a deficit of $96.9 million at December 31, 2012. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our debt offerings in November 2011 and October 2012 to fund ongoing operations, including our 2012 capital program, and to pay down borrowings on our credit facility. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our working capital ratio does not include available liquidity through our credit facility. Our debt to capitalization ratio was 47% and 42% at December 31, 2012 and December 31, 2011, respectively.

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Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2012 were as follows (in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Non-cancelable operating leases (1)	$8,330	$6,534	$1,080	$—	$—	$—	$15,944
Asset retirement obligation (2)	7,134	4,765	4,244	2,694	2,749	65,191	86,777
Drilling rigs and completion services	20,684	—	—	—	—	—	20,684
Geoscience data services	1,777	1,301	—	—	—	—	3,078
Gas transportation and Processing (3)	9,963	10,890	7,752	6,456	3,723	8,385	47,169
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	—	—	—	—	—	400,000	400,000
Interest Cost	69,281	69,281	69,281	69,281	60,375	191,672	529,171
Credit facility (4)	—	—	—	—	39,400	—	39,400
Total	$117,169	$92,771	$82,357	$78,431	$356,247	$890,248	$1,617,223

(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, 2012.
(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 November 2017 and these amounts exclude $0.9 million standby letters of credit outstanding under this facility.

As of December 31, 2012, 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 43.8 MMBoe added in 2012, 58.0 MMBoe added in 2011, and 36.7 MMBoe added in 2010. The 2012 proved reserves additions from drilling activities consisted primarily of additions in the Artesia Wells field in South Texas, based on the results of the horizontal drilling program conducted in this area during the year, and also included additions in the Burr Ferry field. We obtained reasonable certainty regarding these reserves additions by applying the same methodologies that have been used historically in this area. At year-end 2012, 34% of our total proved reserves were proved developed, compared with 35% at year-end 2011 and 45% at year-end 2010.

At year-end 2012, our proved reserves were 192.1 MMBoe with a PV-10 Value of $2.3 billion (PV-10 Value 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), an increase in the PV-10 Value of approximately $366 million, or 19%, from the prior year-end levels. In 2012, our proved natural gas reserves decreased 19.2 Bcf, or 3%, while our proved oil reserves increased 12.3 MMBbl, or 40%, and our NGL reserves increased 23.4 MMBbl, or 90%, for a total equivalent increase of 32.5 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 Value calculation. Our average natural gas price used in the PV-10

Value calculation for 2012 was $2.71 per Mcf. This average price during 2012 was a decrease from $3.89 per Mcf at year-end 2011, compared to $4.08 per Mcf at year-end 2010. Our average oil price used in the PV-10 Value calculation for 2012 was $103.64 per Bbl. This average price during 2012 was slightly lower than the average price of $103.87 per Bbl at year-end 2011, compared to $78.31 in 2010.

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 on a country-by-country basis using the unit-of-production method.

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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 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 cash flow hedges, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

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.

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 to any material degree 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, 2012.

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Forward-Looking Statements

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 production levels, reserve increases, capital expenditures, 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 pricing expectations;
• 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 and transportation of oil and natural gas;
• exploitation or property acquisitions;
• costs of exploiting and developing our properties and conducting other operations;
• competition in the oil and natural gas industry;
• general economic conditions;
• opportunities to monetize assets;
• 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 our annual report on Form 10-K for the year ended December 31, 2012. 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.

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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. This commodity pricing volatility has continued with unpredictable price swings throughout 2012.

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, 2012, we did not have any outstanding derivative instruments in place for future production.

Income Tax Carryforwards. As of December 31, 2012, the Company has net deferred tax carryforward assets of $83.9 million for federal net operating losses, $2.1 for federal alternative minimum tax credits and $7.7 million, net of a $6.0 million valuation allowance, for deferred 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.

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.

Concentration of Sales Risk. 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. For the years ended December 31, 2012, 2011 and 2010, Shell Oil Company and affiliates accounted for 46%, 49% and 52% of our total oil and gas gross receipts, respectively. We believe that the risk of these unsecured receivables is mitigated by the short-term sales agreements we have in place as well as the size, reputation and nature of their business.

Interest Rate Risk. Our senior notes due in 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, 2012, we had $39.4 million drawn 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.

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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, 2012. 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, 2012.

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, 2012, 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.

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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, 2012, 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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012 and our report dated February 22, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 22, 2013

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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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

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, 2012, 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 22, 2013 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 22, 2013

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

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 170	$ 251,696
Accounts receivable	67,318	68,360
Deferred tax asset	5,679	6,603
Other current assets	7,370	5,460
Total Current Assets	80,537	332,119
Property and Equipment:		
Property and Equipment, including $92,579 and $84,146 of unproved property costs not being amortized, respectively	5,192,793	4,466,845
Less – Accumulated depreciation, depletion, and amortization	(2,847,773)	(2,599,079)
Property and Equipment, Net	2,345,020	1,867,766
Other Long-Term Assets	18,504	16,552
Total Assets	$ 2,444,061	$ 2,216,437
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 75,378	$ 95,966
Accrued capital costs	73,190	98,844
Accrued interest	21,362	12,459
Undistributed oil and gas revenues	7,550	8,493
Total Current Liabilities	177,480	215,762
Long-Term Debt	916,934	719,775
Deferred Tax Liabilities	223,243	206,567
Asset Retirement Obligation	79,643	67,115
Other Long-Term Liabilities	9,901	10,709
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 shares authorized, 43,450,367 and 42,969,546 shares issued, and 42,930,071 and 42,485,075 shares outstanding, respectively	435	430
Additional paid-in capital	747,868	726,956
Treasury stock held, at cost, 520,296 and 484,471 shares, respectively	(13,855)	(12,350)
Retained earnings	302,412	281,473
Accumulated other comprehensive loss, net of income tax	—	—
Total Stockholders’ Equity	1,036,860	996,509
Total Liabilities and Stockholders’ Equity	$ 2,444,061	$ 2,216,437

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2012	2011	2010
Revenues:			
Oil and gas sales	$554,194	$602,341	$436,632
Price-risk management and other, net	3,096	(3,210)	1,797
Total Revenues	557,290	599,131	438,429
Costs and Expenses:			
General and administrative, net	46,778	45,362	36,359
Depreciation, depletion, and amortization	247,178	221,230	162,572
Accretion of asset retirement obligation	5,121	4,570	3,956
Lease operating cost	115,470	104,791	81,929
Severance and other taxes	48,862	52,508	45,868
Interest expense, net	57,303	35,566	33,437
Total Costs and Expenses	520,712	464,027	364,121
Income from Continuing Operations Before Income Taxes	36,578	135,104	74,308
Provision for Income Taxes	15,639	50,494	27,833
Income from Continuing Operations	20,939	84,610	46,475
Income (loss) from Discontinued Operations, net of taxes	—	14,211	(181)
Net Income	$20,939	$98,821	$46,294
Per Share Amounts-			
Basic: Income from Continuing Operations	$0.48	$1.96	$1.19
Income (loss) from Discontinued Operations, net of taxes	—	—0.33	—
Net Income	$0.48	$2.29	$1.19
Diluted: Income from Continuing Operations	$0.48	$1.95	$1.18
Income (loss) from Discontinued Operations, net of taxes	—	0.33	—
Net Income	$0.48	$2.27	$1.18
Weighted Average Shares Outstanding - Basic	42,840	42,394	38,300
Weighted Average Shares Outstanding - Diluted	42,930	42,629	38,524

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Comprehensive Income
Swift Energy Company and Subsidiaries (in thousands)

	Year Ended December 31,		
	2012	2011	2010
Net Income:	$20,939	$98,821	$46,294
Other Comprehensive Income:			
Unrealized gains (losses) related to price risk management transactions, before taxes	1,210	(520)	868
Provision (benefit) for income taxes	440	(190)	319
Unrealized gains (losses) related to price risk management transactions, net of taxes	770	(330)	549
Less: reclassification of (gains) losses on price risk management transactions to net income, before taxes	(1,210)	738	(732)
(Provision) benefit for income taxes	(440)	270	(269)
Reclassification of (gains) losses on price risk management transactions to net income, net of taxes	(770)	468	(463)
Other comprehensive income, before income taxes	—	218	136
Provision for income taxes	—	80	51
Other comprehensive income, net of taxes	—	138	85
Comprehensive Income	$20,939	$98,959	$46,379

See accompanying Notes to Consolidated Financial Statements.

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2009	$379	$551,606	$(9,221)	$136,358	$(223)	$678,899
Stock issued for benefit plans (59,335 shares)	—	242	1,271	—	—	1,513
Stock options exercised (136,432 shares)	1	2,086	—	—	—	2,087
Public stock offering (4,038,270 shares)	40	140,099	—	—	—	140,139
Purchase of treasury shares (70,337 shares)	—	—	(1,828)	—	—	(1,828)
Tax benefits from share-based compensation	—	28	—	—	—	28
Employee stock purchase plan (66,564 shares)	1	950	—	—	—	951
Issuance of restricted stock (312,191 shares)	3	(3)	—	—	—	—
Amortization of share-based compensation	—	11,849	—	—	—	11,849
Net Income	—	—	—	46,294	—	46,294
Other comprehensive income	—	—	—	—	85	85
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 share-based 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 share-based compensation	—	16,830	—	—	—	16,830
Net Income	—	—	—	98,821	—	98,821
Other comprehensive income	—	—	—	—	138	138
Balance, December 31, 2011	$430	$726,956	$(12,350)	$281,473	$—	$996,509
Stock issued for benefit plans (50,987 shares)	—	354	1,300	—	—	1,654
Stock options exercised (63,040 shares)	1	635	—	—	—	636
Purchase of treasury shares (86,812 shares)	—	—	(2,805)	—	—	(2,805)

Tax benefits from share-based compensation	—	175	—	—	—	175
Employee stock purchase plan (42,624 shares)	—	1,076	—	—	—	1,076
Issuance of restricted stock (375,157 shares)	4	(4)	—	—	—	—
Amortization of share-based compensation	—	18,676	—	—	—	18,676
Net Income	—	—	—	20,939	—	20,939
Other comprehensive loss	—	—	—	—	—	—
Balance, December 31, 2012	$435	$747,868	$(13,855)	$302,412	$—	$1,036,860

See accompanying Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2012	2011	2010
Cash Flows from Operating Activities:			
Net income	$20,939	$98,821	$46,294
Plus (gain) loss from discontinued operations, net of taxes	—	(14,211)	181
Adjustments to reconcile net income to net cash provided by operating activities-			
Depreciation, depletion, and amortization	247,178	221,230	162,572
Accretion of asset retirement obligation	5,121	4,570	3,956
Deferred income taxes	16,798	48,995	32,881
Share-based compensation expense	13,476	12,625	10,256
Other	976	2,143	1,563
Change in assets and liabilities-			
(Increase) decrease in accounts receivable	3,235	(12,625)	(6,691)
Increase (decrease) in accounts payable and accrued liabilities	(2,102)	10,134	472
Increase (decrease) in income taxes payable	82	(73)	247
Increase in accrued interest	8,903	1,449	7,265
Cash provided by operating activities – continuing operations	314,606	373,058	258,996
Cash used by operating activities – discontinued operations	—	(2)	(41)
Net Cash Provided by Operating Activities	314,606	373,056	258,955
Cash Flows from Investing Activities:			
Additions to property and equipment	(757,755)	(505,332)	(353,648)
Proceeds from the sale of property and equipment	528	50,284	133
Cash used in investing activities – continuing operations	(757,227)	(455,048)	(353,515)
Cash provided by investing activities – discontinued operations	—	5,000	5,000
Net Cash Used in Investing Activities	(757,227)	(450,048)	(348,515)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	157,500	247,890	—
Net proceeds from bank borrowings	39,400	—	—
Net proceeds from issuances of common stock	1,712	2,151	142,917
Purchase of treasury shares	(2,805)	(3,393)	(1,828)
Payments of debt issuance costs	(4,712)	(4,327)	(3,631)
Cash provided by financing activities – continuing operations	191,095	242,321	137,458
Cash provided by financing activities – discontinued operations	—	—	—
Net Cash Provided by Financing Activities	191,095	242,321	137,458
Net Increase (decrease) in Cash and Cash Equivalents	(251,526)	165,329	47,898
Cash and Cash Equivalents at Beginning of Period	251,696	86,367	38,469
Cash and Cash Equivalents at End of Period	$170	$251,696	$86,367
Supplemental Disclosures of Cash Flows Information:			
Cash paid during period for interest, net of amounts capitalized	$46,911	$32,078	$24,622

Cash paid during period for income taxes	$ 248	$ 1,770	$ 200

See accompanying Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Summary of 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 consolidated 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 amounts 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 ended December 31, 2012, 2011 and 2010, such internal costs capitalized totaled $31.1 million, $29.3 million and $24.6 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the years ended December 31, 2012, 2011 and 2010, capitalized interest on unproved properties totaled $7.9 million , $7.7 million and $7.4 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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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.

(in thousands)	December 31, 2012	December 31, 2011
Property and Equipment		
Proved oil and gas properties	$5,058,524	$4,343,867
Unproved oil and gas properties	92,579	84,146
Furniture, fixtures, and other equipment	41,690	38,832
Less – Accumulated depreciation, depletion, and amortization	(2,847,773)	(2,599,079)
Property and Equipment, Net	$2,345,020	$1,867,766

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 two 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”). This calculation is done on a country-by-country basis.

The calculations of the Ceiling Test and provision for DD&A are 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.

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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, 2012 and 2011, 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, 2012 and 2011, 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, 2012, our “Accounts receivable” balance included $53.9 million for oil and gas sales, $3.6 million for joint interest owners and $9.8 million for other receivables. At December 31, 2011, our “Accounts receivable” balance included $58.6 million for oil and gas sales, $4.2 million for joint interest owners and $5.6 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 7.125% senior notes due in 2017 mature on June 1, 2017, and the balance of their issuance costs at December 31, 2012, was $2.2 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at December 31, 2012, was $4.0 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at December 31, 2012, was $7.0 million. The balance of revolving credit facility issuance costs at December 31, 2012, was $4.2 million.

In October 2012, we extended our credit facility and changed the composition of the banks included in our syndicate. Due to this change we recorded a reduction in our unamortized debt issuance costs of $0.7 million, which were included in "Other Long-Term Assets” on the accompanying consolidated balance sheet for the year ended December 31, 2012.

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.

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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. When we entered into the transactions discussed below, 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.

For the years ended December 31, 2012, 2011 and 2010, we recognized net gains (losses) of $2.3 million, ($0.9) million and $0.7 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 amounts been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. The ineffectiveness reported in "Price-risk management and other, net" for the years ended December 31, 2012, 2011 and 2010, was not material.

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 are recorded as a reduction to "General and administrative, net", on the accompanying consolidated statements of operations. Our supervision fees are based on COPAS industry guidelines. The amount of supervision fees charged for the years ended December 31, 2012, 2011 and 2010, respectively, did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $11.3 million, $12.9 million and $12.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment and supplies 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 $5.6 million and $3.6 million at December 31, 2012 and 2011, respectively.

For the year ended December 31, 2011, we recorded a charge of $2.1 million related to inventory obsolescence in "Price-risk management and other, net" on the accompanying consolidated 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. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. As of December 31, 2012, we do not have any accrued liability for uncertain tax positions. During 2012, we reversed our previously accrued liability of $1.0 million for an uncertain tax position on which the statutory audit period expired and recognized the related tax benefit.

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

Our U.S. Federal income tax returns for 2007 forward (except for 2008 which was closed through the IRS audit process), our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2005, and our Texas franchise tax returns after 2007 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.

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Accounts Payable and Accrued Liabilities. The "Accounts payable and accrued liabilities" balances on the accompanying consolidated balance sheets are summarized below (in thousands):

	December 31, 2012	December 31, 2011
Trade accounts payable (1)	$31,128	$42,080
Accrued operating expenses	14,647	15,833
Accrued payroll costs	12,297	14,345
Asset retirement obligation – current portion	7,134	9,279
Accrued taxes	5,373	7,604
Other payables	4,799	6,825
Total accounts payable and accrued liabilities	$75,378	$95,966

(1) Included in "trade accounts payable" are liabilities of approximately $13.3 million and $18.7 million at December 31, 2012 and 2011, respectively, for outstanding checks.

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. For the years ended December 31, 2012, 2011 and 2010, Shell Oil Company and affiliates accounted for 46%, 49% and 52% of our total oil and gas gross receipts, respectively. Southcross Energy accounted for approximately 11% of our total oil and gas gross receipts in 2012, while Flint Hills Resources accounted for approximately 14% of our total oil and gas gross receipts in 2011. 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, 2012 and 2011, these assets were approximately $1.0 million and $1.3 million, respectively. 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, 2012, the Company had no gains or losses recorded in "Accumulated other comprehensive income, net of income tax" on the accompanying consolidated balance sheet. The components of accumulated other comprehensive income and related tax effects for 2012 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2011	$—	$—	$—
Change in fair value of cash flow hedges	1,210	440	770
Effect of cash flow hedges settled during the period	(1,210)	(440)	(770)
Other comprehensive loss at December 31, 2012	$—	$—	$—

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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 as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company 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, 2009	$64,236
Accretion expense	3,956
Liabilities incurred for new wells and facilities construction	1,287
Reductions due to 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
Accretion expense	5,121
Liabilities incurred for new wells and facilities construction	2,195
Reductions due to abandoned wells	(2,824)
Revisions in estimates	5,892
Asset Retirement Obligation as of December 31, 2012	$86,777

During 2012, 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 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, 2012 and 2011, approximately $7.1 million and $9.3 million, respectively, of our asset retirement obligation was 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 4,038,270 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.

New Accounting Pronouncements. In June 2011, the FASB issued ASU No. 2011-5, which changes the required presentation of other comprehensive income. Under the new guidance, entities are now 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 adopted this guidance for the period ending March 31, 2012, which can be seen in our Consolidated Statements of Comprehensive Income.

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2. Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Under the guidance, unvested restricted stock grants 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 years ended December 31, 2012, 2011 and 2010 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the years ended December 31, 2012, 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, 2012, 2011 and 2010 (in thousands, except per share amounts):

	2012 Income from Continuing Operations	Shares	Per Share Amount	2011 Income from Continuing Operations	Shares	Per Share Amount	2010 Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:									
Income from continuing operations, and Share Amounts	$20,939	42,840		$84,610	42,394		$46,475	38,300	
Less: (Income) loss from continuing operations allocated to unvested shares	(448)	—		(1,598)	—		(879)		
Income from continuing operations allocated to common shares	$20,491	42,840	$0.48	$83,012	42,394	$1.96	$45,596	38,300	$1.19
Dilutive Securities:									
Plus: Income from continuing operations allocated to unvested shares	448	—		1,598	—		879		
Less: (Income) loss from continuing operations re-allocated to unvested shares	(447)	—		(1,589)	—		(874)		
Stock Options	—	90		—	235			224	
Diluted EPS:									
Income from continuing operations allocated to common shares, and assumed share conversions	$20,492	42,930	$0.48	$83,021	42,629	$1.95	$45,601	38,524	$1.18

Options to purchase approximately 1.6 million shares at an average exercise price of $33.13 were outstanding at December 31, 2012, while options to purchase approximately 1.4 million shares at an average exercise price of $32.46 were outstanding at December 31, 2011 and options to purchase approximately 1.4 million shares at an average exercise price of $29.67 were outstanding at December 31, 2010. Approximately 1.3 million, 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, 2012, 2011 and 2010, respectively, because these stock options were antidilutive.

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3. Provision (Benefit) for Income Taxes

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

	Year Ended December 31,		
	2012	2011	2010
Income (Loss) from Continuing Operations Before Income Taxes	$36,578	$135,104	$74,308

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

	Year Ended December 31,		
	2012	2011	2010
Current	$(1,144)	$1,616	$(2,957)
Deferred	16,783	48,878	30,790
Total	$15,639	$50,494	$27,833

Current taxes consist of a U.S. Federal income tax benefit of $1.4 million primarily related to an IRS refund and state tax expenses of $0.3 million. 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. However, upon IRS audit of these refunds, the IRS disallowed a portion of the carry back resulting in a charge in current expense during 2011. During 2012, the Joint Committee on Taxation reversed the IRS's decision and the IRS re-issued the refunds. The 2010 and 2012 refunds 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,		
	2012	2011	2010
Income taxes computed at U.S. statutory rate (35%)	$12,803	$47,282	$26,008
State tax provisions (benefits), net of federal benefits	(110)	1,505	641
Cumulative impact of adjustments to net state income tax rate	(854)	(2,663)	(1,718)
Valuation allowance of state carryover tax assets	2,070	2,273	1,681
Non-deductible equity compensation	1,911	1,537	867
Uncertain Tax Positions	(977)	—	—
Other, net	796	560	354
Provision (benefit) for income taxes	$15,639	$50,494	$27,833
Effective rate	42.8%	37.4%	37.5%

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One of the primary upward adjustments in the effective tax rate above the U.S. statutory rate is the non-deductible equity compensation. Non-deductible equity compensation increased tax expense by $1.9 million for 2012, $1.5 million for 2011, and $0.9 million for 2010. The provision for state income tax was a credit of $0.1 million for 2012, $1.5 million for 2011 and $0.6 million for 2010. The state income tax provision for 2012 was $1.3 million before a Louisiana percentage depletion benefit of $1.4 million. Revisions in the Company's long-term state apportionment rates resulted in a net decrease to state income tax deferred liabilities of $0.9 million and $2.7 million at December 31, 2012 and 2011, respectively. The 2012 revisions in the Company's long-term state apportionment rates included a reduction to Louisiana income tax deferred liabilities of $1.3 million which was partially offset by an increase of $0.4 million in the deferred income tax liabilities for other states. However, these adjustments also reduced our future expectation to realize benefits for Louisiana state tax loss carryovers. The Company took a charge of $2.1 million and $2.3 million at December 31, 2012 and 2011, respectively, for a valuation allowance against our Louisiana loss carryovers. In 2012, the Company was able to reverse a previously recorded $1.0 million uncertain tax liability as a result of expiring statutes.

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2012 and 2011 were as follows (in thousands):

	Year Ended December 31,	
	2012	2011
Deferred tax assets:		
Federal net operating loss (“NOL”) carryovers	$ 93,600	$ 54,954
NOLs for excess stock-based compensation	(9,676)	(9,450)
State NOL carryovers	13,686	11,377
Alternative minimum tax credits	2,092	3,451
Other Carryover Items	1,378	1,141
Unrealized share-based compensation	9,096	7,151
Valuation allowance	(6,318)	(3,901)
Other	5,909	7,580
Total deferred tax assets	$ 109,767	$ 72,303
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ (324,031)	$ (270,158)
Other	(3,300)	(2,109)
Total deferred tax liabilities	$ (327,331)	$ (272,267)
Net deferred tax liabilities	$ (217,564)	$ (199,964)
Net current deferred tax assets	5,679	6,603
Net non-current deferred tax liabilities	$ (223,243)	$ (206,567)

Deferred tax assets increased by $37.5 million. The federal NOL carryover tax assets, net of NOLs for excess stock-based compensation, increased by $38.4 million due to an estimated current year tax operating loss. Alternative Minimum Tax ("AMT") credits available for future years decreased by $1.4 million as a result of refunds.

The total change in the deferred tax liability from 2011 to 2012 was an increase of $55.1 million. This increase is primarily attributable to a $53.9 million increase in the deferred liability for oil and gas exploration and development costs which is attributable to tax deductions in excess of book deductions for these costs.

The federal NOL carryovers will expire between 2027 and 2032 if not utilized in earlier periods. The Company's federal NOL carryover net deferred tax assets for the years ended December 31, 2012, 2011 and 2010, were $93.6 million, $55.0 million and $30.7 million, respectively, including deferred tax benefits for excess stock-based compensation deductions. Deferred tax benefits for excess stock-based compensation deductions in the amount of $9.7 million for 2012, $9.5 million for 2011 and $7.6 million for 2010 represent stock-based compensation that have generated tax deductions that have not yet resulted in a cash tax benefit because the Company has NOL carryovers. The Company plans to recognize the federal NOL net deferred tax assets associated with excess stock-based compensation tax deductions only when all other components of the federal NOL carryover tax assets

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have been fully utilized. If and when the excess stock-based compensation related NOL carryover tax assets are realized, the benefit will be credited directly to equity. The other primary carryover item is a $13.7 million net deferred tax asset, offset by a $6.0 million valuation allowance for State of Louisiana NOLs. These loss carryovers are scheduled to expire between 2013 and 2027.

Unrealized share-based compensation accounts for $9.1 million in deferred tax assets. These amounts are attributable to share-based 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.

The total change in the valuation allowance from 2011 to 2012 was an increase of $2.4 million. This increase is related to a charge of $2.1 million for a valuation allowance against our Louisiana net operating losses and $0.3 million for a valuation allowance against charitable contribution carryforwards.

The Internal Revenue Service (IRS) has 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.

4. Long-Term Debt

Our long-term debt as of December 31, 2012 and 2011, was as follows (in thousands):

	December 31, 2012	December 31, 2011
7.125% senior notes due in 2017	$ 250,000	$ 250,000
8.875% senior notes due in 2020 (1)	222,147	221,873
7.875% senior notes due in 2022 (1)	405,387	247,902
Bank Borrowings	39,400	—
Long-Term Debt (1)	$ 916,934	$ 719,775

(1) Amounts are shown net of any debt discount or premium

As of December 31, 2012, our bank borrowings of $39.4 million are due in 2017. The maturities on our senior notes were $250.0 million in 2017, $225.0 million in 2020 and $400.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $7.9 million, $7.7 million and $7.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Bank Borrowings. On October 31, 2012, we renewed and extended the maturity of our $500.0 million credit facility with a syndicate of 11 banks from May 12, 2016 to November 1, 2017. We also increased the borrowing base and commitment amount to $450.0 million from a previous borrowing base and commitment amount of $375.0 million and $300.0 million, respectively, at September 30, 2012. As of December 31, 2012, our borrowing base and commitment amount was $450.0 million.

At December 31, 2012, we had $39.4 million in outstanding borrowings under our credit facility while at December 31, 2011, we did not have any borrowings under our credit facility. The interest rate on our credit facility is either (a) the lead bank’s prime rate plus an applicable margin or (b) the 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 0.5%, 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. At December 31, 2012, the lead bank’s prime rate was 3.25% and the commitment fee associated with the first $225.0

million unfunded portion of the borrowing base was set at 37.5 basis points while the commitment fee on any remaining unfunded portion was set at 50 basis points.

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, 2012, 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.

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Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $3.7 million, $2.4 million and $1.9 million for the years ended December 31, 2012, 2011 and 2010, respectively. The amount of commitment fees included in interest expense, net was $1.4 million, $1.5 million and $1.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

In October 2012, we extended our credit facility and changed the composition of the banks included in our syndicate. Due to this change we recorded a reduction in our unamortized debt issuance costs of $0.7 million, which was recorded in "Other Long-Term Assets" on the accompanying consolidated balance sheets and a charge of $0.7 million to "Interest expense, net" on the accompanying consolidated statements of operations for the year ended December 31, 2012.

Senior Notes Due In 2022. At December 31, 2012, these notes consisted of $400.0 million of 7.875% senior notes that will mature on March 1, 2022. On November 30, 2011, we issued $250.0 million of these senior notes at a discount of $2.1 million or 99.156% of par, which equates to an effective yield to maturity of 8%. The original discount of $2.1 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes. On October 3, 2012, we issued an additional $150.0 million of these senior notes at 105% of par, which equates to a yield to worst of 6.993%. The premium of $7.5 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The net cash proceeds from the recent issuance were $156.8 million. 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 commenced 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 $7.4 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2012. Under the terms of the sale of the original $250.0 million of senior notes due in 2022, Swift was required to offer to exchange these notes for registered notes with the same terms. We completed the exchange in May 2012.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $22.4 million and $1.7 million for the years ended December 31, 2012 and 2011.

Senior Notes Due In 2020. These notes consist of $225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. 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 notes using the effective interest method. 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2012.

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Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $20.6 million for the years ended December 31, 2012 and 2011 and $20.5 million for the year ended December 31, 2010, respectively.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 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. 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 the principal, starting on June 1, 2015 and declining in twelve-month intervals to 100% on June 1, 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, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates, consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2012.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $18.2 million for the years ended December 31, 2012 and 2011 and $18.4 million for the year ended December 31, 2010, respectively.

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 both 2012 and 2011 and $5.4 million in 2010. Rental and lease expenses which were included in “Lease operating cost” on our accompanying consolidated statements of operations were $14.3 million, $13.9 million and $10.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our remaining minimum annual obligations under non-cancelable operating lease commitments were $8.3 million for 2013, $6.5 million for 2014, $1.1 million for 2015 and $15.9 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 10-year lease expiring in 2015. This lease is renewable for two terms of 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, 2012 for these services and materials totaled $20.7 million through 2013.

Our employment agreement liabilities for certain named executive officers, as detailed in our most recent proxy statement, constitute the majority of other long-term liabilities on the balance sheet at both December 31, 2012 and 2011.

Our remaining gas transportation and processing minimum obligations were $10.0 million for 2013, $10.9 million for 2014, $7.8 million for 2015, $6.5 million for 2016, $3.7 million for 2017 and $47.2 million in the aggregate.

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

6. Share-Based Compensation

Share-Based Compensation Plans. We have three stock option plans that awards are currently outstanding under, the 2005 Share-Based 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 Share-Based 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 Share-Based Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the 2005 Share-Based 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 for stock options equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested over a three year period, 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 previously included 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. This reload feature was discontinued during 2012. 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 Share-Based 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 42,624 shares at a price of $25.26 in 2012, 49,089 shares at a price of $20.37 in 2011, 66,564 shares at a price of $14.29 in 2010. The contributions for the years ended December 31, 2012, 2011 and 2010 were all made in common stock. As of December 31, 2012, 477,481 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, 2012, 2011 and 2010, we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were $0.6 million, $1.2 million and $2.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. The actual income tax benefit from stock option exercises was $0.3 million, $1.1 million and $0.8 million for the same periods, respectively.

Share-based compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying consolidated statements of operations, was $12.6 million, $11.9 million and $9.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. Share-based compensation recorded in lease operating cost was $0.3 million for the years ended December 31, 2012, 2011 and 2010, respectively. We also capitalized $5.2 million, $4.2 million and $1.6 million of share-based compensation for the years ended December 31, 2012, 2011 and 2010, respectively.

Our shares available for future grant under our Share-Based Compensation plans were 1,622,049 at December 31, 2012. 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.

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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 options issued during the indicated periods:

	Twelve Months Ended December 31,		
	2012	2011	2010
Dividend yield	0%	0%	0%
Expected volatility	61.2%	58.8%	62.8%
Risk-free interest rate	0.8%	1.9%	2.1%
Expected life of options (in years)	4.3	3.8	4.3
Weighted-average grant-date fair value	$15.71	$19.17	$12.60

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 2012, 2011 and 2010 stock option grants.

At December 31, 2012, we had $3.2 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 0.8 years. The following table represents stock option activity for the years ended December 31, 2012, 2011 and 2010:

	2012		2011		2010	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg Exer. Price	Shares	Wtd. Avg Exer. Price
Options outstanding, beginning of period	1,375,281	$32.46	1,361,779	$29.67	1,289,194	$29.72
Options granted	336,092	$32.39	307,394	$42.56	273,463	$25.28
Options canceled	(42,047)	$41.20	(67,529)	$55.19	(36,983)	$44.65
Options exercised (1)	(83,732)	$14.70	(226,363)	$22.61	(163,895)	$18.11
Options outstanding, end of period	1,585,594	$33.13	1,375,281	$32.46	1,361,779	$29.67
Options exercisable, end of period	990,957	$32.39	734,985	$31.07	749,447	$32.04

[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 previously included 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. This reload feature was discontinued during 2012. 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. Mature shares that were delivered in “stock swap” transactions which resulted in the issuance of an equal number of reload option were 20,692, 79,194 and 27,463 for the years ended December 31, 2012, 2011 and 2010, respectively, .

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at December 31, 2012 was $0.2 million and 6.0 years and $0.2 million and 4.7 years, respectively. The total intrinsic value of options exercised for the years ended December 31, 2012, 2011 and 2010 was $0.9 million, $4.2 million and $2.6 million, respectively.

The following table summarizes information about stock options outstanding at December 31, 2012:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/12	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/12	Wtd. Avg. Exercise Price
$8.00 to $24.99	478,697	5.7	$19.42	396,690	$18.36
$25.00 to $44.99	1,074,221	6.3	$38.76	561,591	$41.33
$45.00 to $65.00	32,676	0.8	$49.04	32,676	$49.04
$8.00 to $65.00	1,585,594	6.0	$33.13	990,957	$32.39

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Restricted Stock

For the years ended December 31, 2012, 2011 and 2010, the Company issued 543,800, 499,050 and 388,650 shares, respectively, of restricted stock to employees, consultants, and directors. These shares vest over three years and remain subject to forfeiture if vesting conditions are not met. The fair values of these shares when issued, for the years ended December 31, 2012, 2011 and 2010 were $31.12, $40.28 and $25.41 per share, respectively.

The compensation expense for these awards was determined based on the closing 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, 2012, we had unrecognized compensation expense of $15.2 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 0.9 years. The grant date fair values of shares vested for the years ended December 31, 2012, 2011 and 2010 were $10.0 million, $8.7 million and $9.0 million, respectively.

The following table represents restricted stock activity for the years ended December 31, 2012, 2011 and 2010:

	2012		2011		2010	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	834,703	$31.89	734,286	$22.87	703,856	$24.15
Restricted shares granted	543,800	$31.12	499,050	$40.28	388,650	$25.41
Restricted shares canceled	(107,182)	$33.95	(49,661)	$32.29	(46,029)	$24.45
Restricted shares vested	(375,157)	$26.62	(348,972)	$24.84	(312,191)	$28.75
Restricted shares outstanding, end of period	896,164	$33.38	834,703	$31.89	734,286	$22.87

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, 2012, 2011 and 2010, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2012, 2011 and 2010, 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 12,995, 6,729 and 5,108 for the years ended December 31, 2012, 2011 and 2010, 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 Energy 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 $1.5 million, $1.4 million and $1.3 million for the years ended December 31, 2012, 2011 and 2010, respectively, and are recorded as “General and administrative, net” on the accompanying consolidated statements of operations. The contributions were all made in common stock, from treasury shares. The shares of common stock contributed to the 401(k) savings plan totaled 91,895, 44,258 and 31,960 for the years ended December 31, 2012, 2011 and 2010, respectively.

Shareholder Rights Plan. Our Rights Agreement was initially adopted by the Board of Directors in 1997 for a ten-year term and was renewed and extended for an additional ten-year term on December 21, 2006. Effective March 1, 2012, we entered into an amendment with our transfer agent, American Stock Transfer & Trust Company, to accelerate the final expiration date of the Rights Plan and the rights issued thereunder from December 20, 2016 to the close of business on March 1, 2012.

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

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries (continued)

Officer. We paid Tec-Com, for services pursuant to the terms of the contract, approximately $0.6 million in 2012, 2011 and 2010. The contract was renewed on July 1, 2010 on substantially the same terms as the previous contract and expires June 30, 2013.

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 payments of $5.0 million to be received 9 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.

Our income from discontinued operations, net of taxes was $14.2 million for the year ended December 31, 2011, which equated to $0.33 per basic and diluted share.

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. No gain or loss was recognized from this divestiture.

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.

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, 2012, 2011 and 2010, the fair value and carrying value of our senior notes was as follows (in millions):

	December 31, 2012	December 31, 2011	December 31, 2010
	Fair Value	Fair Value	Fair Value

		Carrying Value		Carrying Value		Carrying Value
7.125% senior notes due in 2017	$258.1	$250.0	$254.8	$250.0	$254.7	$250.0
8.875% senior notes due in 2020	$244.4	$222.1	$239.6	$221.9	$242.3	$221.6
7.875% senior notes due in 2022	$424.0	$405.4	$252.8	$247.9	$—	$—

Our senior notes due in 2017, 2020 and 2022 are stated at carrying value on our financial statements, net of any discount or premium. If we recorded these notes at fair value they would be level 1 in our fair value hierarchy as they are traded in an active market with quoted prices for identical instruments.

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries (continued)

At December 31, 2012, the Company did not have any derivative instruments. The following table presents our assets that are measured at fair value as of December 31, 2011, and are categorized using the fair value hierarchy. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2011				
Oil Floors	$0.1	$—	$0.1	$—

Our derivatives, measured at fair value in the table above, are recorded in "Other current assets" on the accompanying consolidated balance sheets.

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category have comparable fair values for identical instruments in active markets.

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 (the parent) is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is the sole guarantor of our senior notes due in 2017, 2020 and 2022. Swift Energy Company does not have any independent assets or operations. The guarantees on our senior notes due in 2017, 2020 and 2022 are full and unconditional. Any subsidiaries of Swift Energy Company, other than Swift Energy Operating, LLC, are minor.

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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, 2012	
Proved oil and gas properties	$5,058,524
Unproved oil and gas properties	92,579
	5,151,103
Accumulated depreciation, depletion, and amortization	(2,818,890)
Net capitalized costs	$2,332,213
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

There were $92.6 million of domestic unproved property costs at December 31, 2012, excluded from the amortizable base. Of this amount, $23.5 million was incurred in 2012, $21.1 million was incurred in 2011, $19.6 million was incurred in 2010 and $28.4 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, 2012 and 2011.

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,		
	2012	2011	2010
Lease acquisitions and prospect costs 1	$52,840	$52,779	$60,641
Exploration	—	—	83,957
Development 2	670,251	540,714	276,024
Total acquisition, exploration, and development 3, 4	$723,091	$593,493	$420,622

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 for the years ended December 31, 2012, 2011 and 2010 were $37.2 million, $41.8 million and $50.3 million, respectively. Domestic costs for seismic data acquisition, included above, were $2.8 million for 2012 and 2011 and $6.1 million for 2010, respectively.

2) Facility construction costs and capital costs have been included in development costs, and totaled $81.3 million, $42.8 million and $29.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

3) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $31.1 million, $29.3 million and $24.6 million for the years ended December 31, 2012, 2011 and 2010, respectively. In addition, the total includes $7.9 million, $7.7 million and $7.4 million for the years ended December 31, 2012, 2011 and 2010, respectively, of capitalized interest on unproved properties.

4)Asset retirement obligations incurred, of approximately $5.3 million, $20.7 million and $10.7 million, have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2012, 2011 and 2010, respectively.

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Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were determined by us, and our reserves were audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy has audited 96%, 94% and 98% of our domestic proved reserves for the years ended December 31, 2012, 2011 and 2010.

Estimates of Proved Reserves	Total (Boe)	Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
Proved reserves as of December 31, 2009	112,928,443	290,552,922	44,490,380	20,012,576
Revisions of previous estimates (1)	(8,487,441)	5,898,299	(9,085,180)	(385,310)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place	—	—	—	—
Extensions, discoveries, and other additions (3)	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 estimates (1)	(4,657,802)	4,302,241	(3,294,117)	(2,080,725)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place (4)	(16,049,309)	(64,765,392)	(3,876,295)	(1,378,782)
Extensions, discoveries, and other additions (3)	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
Revisions of previous estimates (1)	397,835	(97,311,524)	5,175,468	11,440,954
Purchases of minerals in place	—	—	—	—
Sales of minerals in place	—	—	—	—
Extensions, discoveries, and other additions (3)	43,813,417	114,506,574	10,925,490	13,803,498
Production	(11,700,398)	(36,385,672)	(3,773,856)	(1,862,263)
Proved reserves as of December 31, 2012	192,072,642	597,568,985	43,258,614	49,219,197
Proved developed reserves (2):				
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
December 31, 2012	65,714,713	195,642,512	17,779,798	15,327,830

(1) Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, reservoir pressure and commodity pricing. Performance-related upward revisions in the liquids rich Artesia Wells field during 2012 were offset by downward revisions in the South Texas area due to low natural gas prices. Proved reserves, as of December 31, 2012, 2011 and 2010 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 hedging activity during the year did not materially affect prices used in these calculations for the years ended December 31, 2012, 2011 and 2010. The 12-month 2012 average adjusted prices after differentials used in our calculations were $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL compared to $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL for the 12-month average 2011 prices and $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.

(2) At December 31, 2012, 2011 and 2010, 34%, 35% and 45% of our reserves were proved developed, respectively.

(3) We have added proved reserves primarily through our drilling activities, including 43.8 MMBoe added in 2012, 58.0 MMBoe added in 2011 and 36.7 MMBoe added in 2010. The 2012 and 2011 proved reserves additions from drilling activities consisted primarily 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.

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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,		
	2012	2011	2010
Future gross revenues	$8,376,948	$6,895,214	$5,768,030
Future production costs	(2,257,087)	(1,754,844)	(1,384,275)
Future development costs	(2,045,977)	(1,863,492)	(1,441,901)
Future net cash flows before income taxes	4,073,884	3,276,878	2,941,854
Future income taxes	(906,125)	(778,053)	(746,845)
Future net cash flows after income taxes	3,167,759	2,498,825	2,195,009
Discount at 10% per annum	(1,296,058)	(981,204)	(850,301)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$1,871,701	$1,517,621	$1,344,708

The standardized measure of discounted future net cash flows from production of proved reserves for the year ended December 31, 2012, was developed as follows:

1. Estimates were 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 were 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 were reduced by estimated future costs to develop and to produce the proved reserves, including asset retirement obligation costs, based on year-end cost estimates and the estimated effect of future income taxes.
4. Future income taxes were 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.

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.

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The following are the principal sources of changes in the standardized measure of discounted future net cash flows (in thousands) for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2010
Beginning balance	$ 1,517,620	$ 1,344,708	$ 1,020,457
Revisions to reserves proved in prior years			
Net changes in prices, net of production costs	(156,121)	283,310	501,997
Net changes in future development costs	(22,300)	(15,534)	(47,935)
Net changes due to revisions in quantity estimates	7,060	(105,438)	(186,180)
Accretion of discount	191,761	177,691	132,231
Other	(72,269)	61,676	(80,393)
Total revisions	(51,869)	401,705	319,720
New field discoveries and extensions, net of future production and development costs	663,572	103,983	325,561
Purchases of minerals in place	—	—	—
Sales of minerals in place	—	(172,870)	—
Sales of oil and gas produced, net of production costs	(389,862)	(445,043)	(308,834)
Previously estimated development costs incurred	144,606	252,931	118,147
Net change in income taxes	(12,366)	32,206	(130,343)
Net change in standardized measure of discounted future net cash flows	354,081	172,912	324,251
Ending balance	$ 1,871,701	$ 1,517,620	$ 1,344,708

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2012 and 2011 (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
2012						
First	$ 135,878	$ 5,882	$ 3,570	$ —	$ 0.08	$ 0.08
Second	134,757	5,115	3,028	—	0.07	0.07
Third	128,750	5,544	3,122	—	0.07	0.07
Fourth	157,905	20,037	11,219	—	0.26	0.26
Total	$ 557,290	$ 36,578	$ 20,939	$ —	$ 0.48	$ 0.48
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

There were no extraordinary items in 2012 or 2011. 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.

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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, 2012 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, 2012 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.

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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 21, 2013, 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 21, 2013, 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 21, 2013, 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 21, 2013, 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 21, 2013, 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 22, 2013, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

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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	Third Amended and Restated Bylaws of Swift Energy Company, effective February 12, 2013 (incorporated by reference as Exhibit 3.2 to Swift Energy Company's Form 8-K filed February 14, 2013, 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	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 October 18, 2012, 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 4.3 to Swift Energy Company's Form 8-K filed October 24, 2012, File No. 1-08754).
10.1+	Amended and Restated 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 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+	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).

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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 First Amended and Restated 2005 Stock Compensation Plan dated April 1, 2009 (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 First Amended and Restated 2005 Stock Compensation Plan dated May 12, 2009 (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 First Amended and Restated 2005 Stock Compensation Plan dated May 11, 2010 (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 First Amended and Restated 2005 Stock Compensation Plan dated May 10, 2011 (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+	Revised Amendment No. 5 to the First Amended and Restated 2005 Stock Compensation Plan dated May 2, 2012 (incorporated by references as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 2, 2012, File No. 1-08754).
10.10+	Amendment No. 6 to the First Amended and Restated 2005 Stock Compensation Plan dated February 13, 2012 (incorporated by reference as Exhibit 99.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 filed May 3, 2012, File No. 1-08754).
10.11+	Amendment No. 7 to the First Amended and Restated 2005 Stock Compensation Plan dated May 8, 2012 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 11, 2012, File No. 1-08754).
10.12+	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).
10.13+	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).
10.14+	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).
10.15+	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).

10.16+	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).
10.17	Second Amended and Restated Credit Agreement 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).

10.18	Third Amendment to Second Amended and Restated Credit Agreement effective as of October 3, 2012, among Swift Energy Company, Swift Energy Operating, LLC and JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the Swift Energy Company's Form 8-K filed November 15, 2012. File No. 1-08754).
10.19	Second Amendment to Second Amended and Restated Credit Agreement effective as of October 2, 2012, among Swift Energy Company, Swift Energy Operating, LLC and JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the Swift Energy Company's Form 8-K filed October 3, 2012, File No 1-08754).
10.20	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 10.1 to Swift Energy Company's Form 8-K filed May17, 2011, File No. 1-08754).
10.21	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).
10.22+	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).
10.23+	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).
10.24+	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).
10.25+	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).
10.26+	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).
10.27+	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).

10.28	Purchase Agreement, dated October 3, 2012 among Swift Energy Company, Swift Energy Operating, LLC 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 October 5, 2012, File No. 1-08745).
12 *	Swift Energy Company Ratio of Earnings to Fixed Charges.
21 *	List of Subsidiaries of Swift Energy Company.

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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 29, 2013.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Debinition Linkbase Document

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

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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 22, 2013
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice-President Principal Financial Officer	February 22, 2013
/s/ Barry S. Turcotte Barry S. Turcotte	Vice-President Controller Principal Accounting Officer	February 22, 2013
/s/ Deanna L. Cannon Deanna L. Cannon	Director	February 22, 2013

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/s/ Douglas J. Lanier Douglas J. Lanier	Director	February 22, 2013
/s/Greg Matiuk Greg Matiuk	Director	February 22, 2013
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	February 22, 2013
/s/ Charles J. Swindells Charles J. Swindells	Director	February 22, 2013
/s/ Bruce H. Vincent Bruce H. Vincent	Director	February 22, 2013