SWIFT ENERGY CO
Form 10-K/A
November 17, 2014

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

FORM 10-K/A
(Amendment No. 1)

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

For the Fiscal Year Ended December 31, 2013

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 o No þ

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 þ No o

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

1

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, 2013, the last business day of June 2013, was approximately $504,125,149.

The number of shares of common stock outstanding as of January 31, 2014 was 43,475,471.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 20, 2014	Part III, Items 10, 11, 12, 13 and 14

2

Explanatory Note

We are filing this amended Form 10-K/A ("Form 10-K/A") to amend our Annual Report on Form 10-K for the year ended December 31, 2013, originally filed with the Securities and Exchange Commission (the "SEC") on March 3, 2014 ("Original Filing"), to restate our consolidated financial statements and related footnote disclosures for the years ended December 31, 2013, 2012 and 2011. This Form 10-K/A also includes certain restated quarterly information under the Supplementary Information heading in Item 8 of this Form 10-K/A. This Form 10-K/A also amends certain other Items in the Original Filing, as listed in "Items Amended in this Form 10-K/A" below.

Restatement Background

On November 10, 2014, the Audit Committee of our Board of Directors (the "Audit Committee"), after discussion with management and Ernst & Young LLP ("EY"), our independent registered public accounting firm, determined that the following financial statements previously filed with the SEC should no longer be relied upon: (1) the audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2013, 2012 and 2011; (2) the unaudited condensed consolidated financial statements included in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2013 and 2012, June 30, 2013 and 2012, and September 30, 2013 and 2012; and (3) the unaudited condensed consolidated financial statements included in our quarterly reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014. Similarly, the related press releases, auditor reports on the consolidated financial statements as of and for the year ended December 31, 2013 and the effectiveness of internal control over financial reporting as of December 31, 2013, management's report on the effectiveness of internal control over financial reporting as of December 31, 2013, and stockholder communications describing the portion of our financial statements for these periods that need to be restated should no longer be relied upon.

In connection with the preparation of our financial statements for the quarter ended September 30, 2014, we determined that an error occurred in our model used for the ceiling test calculation prepared at December 31, 2013, March 31, 2009 and December 31, 2008, to determine whether the net book value of the Company's oil and gas properties exceed the ceiling. Specifically, this error related to incorrectly including the deferred income tax effect of the Company's asset retirement obligations when computing the ceiling test limitation of its oil and natural gas properties under the full-cost method of accounting. The Company determined that the error caused a material overstatement of its full-cost ceiling test write-down of oil and gas properties in periods prior to 2014, including associated depletion for all periods presented. As a result of this error, we have restated our audited consolidated financial statements for the years ended December 31, 2013, 2012 and 2011 and our unaudited condensed consolidated financial information for the quarters ended March 31, 2013, June 30, 2013, September 30, 2013, and December 31, 2013.

As of December 31, 2013, the correction of this error principally increased the Company's net oil and gas property balances by approximately $49 million, increased the net deferred tax liabilities by approximately $18 million, and increased retained earnings by approximately $31 million. Approximately $15 million of the increase in retained earnings is related to periods prior to 2013, more specifically to the first quarter of 2009 and the fourth quarter of 2008. For the year ended December 31, 2013, the correction of the ceiling test error also resulted in a decrease in our ceiling-test write-down for the year ended December 31, 2013 of approximately $27 million, which was partially offset by an increase in our depreciation, depletion and amortization expense for the year of approximately $1 million. Further, these corrections increased net income for the year ended December 31, 2013 by approximately $16 million (net of an increase to the income tax benefit of approximately $9 million for the period). Please refer to Note 1A - "Restatement of Previously Issued Consolidated Financial Statements" of this Form 10-K/A for more information regarding the impact of these adjustments.

Along with restating our financial statements to correct the error discussed above, we are making adjustments for certain previously identified immaterial accounting errors related to the periods covered by this Form 10-K/A. When these financial statements were originally issued, we assessed the impact of these errors and concluded that they were not material to our financial statements for each of the years ended December 31, 2013, 2012, and 2011, and reported fiscal quarters within each of these years. However, in conjunction with our need to restate our financial statements as a result of the error noted above, we have determined that it would be appropriate within this Form 10-K/A to record all such previously unrecorded adjustments. Please refer to Note 1A - "Restatement of Previously Issued Consolidated Financial Statements" of this Form 10-K/A for more information regarding the impact of these adjustments.

Because these revisions are treated as corrections of errors to our prior period financial results, the revisions are considered to be a "restatement" under U.S. generally accepted accounting principles. Accordingly, the revised financial information included in this Annual Report on Form 10-K/A has been identified as "restated".

Restatement of Other Financial Statements

In addition to this Form 10-K/A, we are concurrently filing an amendment to our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014 (the "Form 10-Q/As"). We are filing the Form 10-Q/As to restate our unaudited condensed consolidated financial statements and related financial information for the periods contained in those reports and to amend certain other Items within those reports.

Internal Control Consideration

Our management has determined that there was a deficiency in our internal control over financial reporting that constitutes a material weakness, as defined by SEC regulations, at December 31, 2013, as discussed in Part II, Item 9A of this Form 10-K/A.

Items Amended in this Form 10-K/A

For the convenience of the reader, this Form 10-K/A sets forth the Original Filing, in its entirety, as modified and superseded as necessary to reflect the restatement. The following items in the Original Filing have been amended as a result of, and to reflect, the restatement:

A. Part II, Item 6. Selected Financial Data

B. Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

C. Part II, Item 8. Financial Statements and Supplementary Data

D. Part II, Item 9A. Controls and Procedures

E. Part IV, Item 15. Exhibits, Financial Statement Schedules

This report on Form 10-K/A is presented as of the filing date of the Original Form 10-K and does not reflect events occurring after that date, or modify or update the information contained therein in any way other than as required to correct the error and record the adjustments described above.

In accordance with applicable SEC rules, this Form 10-K/A includes new certifications required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002, as amended, from our Chief Executive Officer and Chief Financial Officer dated as of the filing date of this Form 10-K/A.

Form 10-K/A
Swift Energy Company and Subsidiaries

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 20, 2014

Items 1 and 2. Business and Properties

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

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and natural gas properties, with a focus on oil and natural gas reserves in Texas as well as onshore and in the inland waters of Louisiana. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. At December 31, 2013, we had estimated proved reserves of 219.2 MMBoe with a PV-10 Value of $2.4 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, 2013 were approximately 24% crude oil, 62% natural gas, and 14% NGLs while 29% of our total proved reserves were developed. Our proved reserves are concentrated with 80% in Texas and 20% 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
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 116.4 MMBoe to 219.2 MMBoe over the five-year period ended December 31, 2013. Over the same period, our annual production has grown from 10.0 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 2013, our proved reserves increased by 14%, 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.

2014 Strategy

We currently plan to fund our 2014 capital expenditures with our 2014 operating cash flow, potential line of credit borrowings and proceeds from asset dispositions and/or joint ventures. Our 2014 planned capital expenditures are $300 to $350 million. These amounts are flexible and will be adjusted based on the timing of any announced transactions and market fundamentals. The Company is currently negotiating the sale of some or all of its properties in Central Louisiana and is also negotiating joint venture arrangements for a portion of our natural gas Eagle Ford properties to accelerate drilling and development, monetize a portion of those asset values, diversify our risk profile and possibly free up capital dollars for other purposes. The Company expects these transactions will be finalized by the end of the second quarter. The completion of one or both of these transactions will affect the level of our 2014 capital expenditures as we better align our capital expenditures with our expected cash flows. We will continue to rationalize our portfolio to focus on properties that generate the most attractive returns on capital.

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 sites, 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 300% 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 $10.28, $10.02 and $9.95 per Boe for the years ended December 31, 2013, 2012 and 2011, 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 99% of our proved oil and natural gas reserves base as of December 31, 2013. 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 and 2012 we merged and prestack time migrated 800 square miles of this data that we are using to plan our wells and enhance and expand our developments at AWP and the Artesia Wells area. We continue to apply our advanced inversion techniques and improve and expand our rock properties understanding which allows us to identify and drill within the most highly productive zones in the Eagle Ford and Olmos formations.

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 and increased our average daily net production from less than 700 Boe to a historical peak of over 18,000 Boe several years ago. We have utilized enhanced 3-D seismic and various completion techniques including sliding sleeves to improve drilling success and production performance. In 2013 we commenced the application of advanced inversion techniques to identify new drilling opportunities around the Lake Washington salt dome. When we acquired this field we booked 7.7 MMBoe of reserves. Since acquisition we produced approximately 52 MMBoe and still have remaining proved reserves of 12.0 MMBoe.

Experienced Technical Team and Technology Utilization

We employ 59 oil and gas technical professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers, who have an average of approximately 23 years of experience in their technical fields and have been employed by us for an average of approximately seven 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 the past three years, we completed projects to invert, calibrate, merge and prestack time-migrate our 800 square miles of merged 3-D seismic data over and near our AWP and Artesia Wells fields. In 2013, we initiated a project to license high-quality 3-D seismic and apply advanced inversion techniques over our Fasken field.

The application of horizontal drilling and multi-stage hydraulic fracturing technology has resulted in increases in production and decreases in completion and operating costs in our South Texas Olmos and Eagle Ford operations. In 2013, we successfully drilled 42 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.

Operating Areas

The following table sets forth information regarding our 2013 year-end proved reserves from continuing operations of 219.2 MMBoe and production of 11.7 MMBoe by area:

Core Areas & Fields	Developed Reserves (MMBoe)	Undeveloped Reserves (MMBoe)	Total Proved Reserves (MMBoe)	% of Total Proved Reserves		Oil and NGLs as % of Reserves		% of Total Production		Oil and NGLs as % of Production	
Artesia Wells - Eagle Ford	9.6	14.8	24.4	11.1	%	48.9	%	24.3	%	49.7	%
AWP - Eagle Ford	11.6	28.1	39.7	18.1	%	70.1	%	17.8	%	71.1	%
AWP - Olmos	15.1	3.6	18.7	8.5	%	41.4	%	19.7	%	43.5	%
Fasken - Eagle Ford	10.3	77.3	87.6	40.0	%	—	%	12.5	%	0.2	%
Other South Texas	4.3	—	4.3	1.9	%	47.9	%	2.4	%	50.1	%
Total South Texas	50.9	123.8	174.7	79.6	%			76.7	%		

Southeast Louisiana	7.5	6.7	14.2	6.5	%	86.2	%	15.3	%	87.6	%
Central Louisiana	4.4	25.8	30.2	13.8	%	71.4	%	7.6	%	67.1	%
Other	0.1	—	0.1	0.1	%	0.6	%	0.4	%	35.6	%
Total	62.9	156.3	219.2	100.0	%	38.0	%	100.0	%	53.2	%

Focus Areas

Our operations are primarily focused in three core areas identified as South Texas, Southeast Louisiana and Central Louisiana. In addition, we have a strategic growth area with acreage in the Four Corners area of southwest Colorado. South Texas is the oldest of our core areas, with our operations first established in the AWP field in 1989 and subsequently expanded with the acquisition of the Sun TSH and Fasken area during 2007. Operations in our Central Louisiana area began in mid-1998 when we acquired the Masters Creek field in Louisiana, 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 2013, the Company drilled 20 wells in our AWP Eagle Ford field, of which one was a joint venture well. The Company owns a 50% working interest in joint venture wells. All wells in this field were drilled and are operated by Swift Energy. At December 31, 2013, we had identified 104 proved undeveloped locations. Our December 31, 2013 proved reserves in this formation are 30% natural gas, 18% NGLs, and 52% oil on a Boe basis.

AWP - Olmos. In the Olmos formation, from which the Company has been producing since 1989, we drilled three horizontal Olmos wells in 2013. 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 59% natural gas, 31% NGLs, and 11% oil on a Boe basis. At December 31, 2013, we had 7 proved undeveloped locations in the Olmos.

Artesia Wells - Eagle Ford. During 2013, the Company drilled 14 operated wells in the Artesia Wells Eagle Ford area. These wells were drilled and are operated by Swift Energy. Our December 31, 2013 proved reserves in this formation are 51% natural gas, 38% NGLs, and 11% oil on a Boe basis. At December 31, 2013, we had identified 35 proved undeveloped locations.

Fasken - Eagle Ford. During 2013, the Company drilled five operated wells in the Fasken Eagle Ford area. Our reserves in this Eagle Ford formation are 100% natural gas. At December 31, 2013, we had identified 58 proved undeveloped locations.

Pursuit of Eagle Ford Joint Venture. We are currently negotiating a joint venture arrangement with prospective partner(s) in order to monetize our highest value acreage in our Eagle Ford natural gas 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 end of the second quarter of 2014.

Southeast Louisiana

Lake Washington. As of December 31, 2013, we owned drilling and production rights in 16,697 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 12.0 MMBoe in this field as of December 31, 2013, 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 2013 we drilled 2 development wells of which one was a dry hole. In our production optimization program we performed 17 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At December 31, 2013, we had 44 proved undeveloped locations in this field.

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, 2013, we owned drilling and production rights in approximately 14,254 net acres in the Bay de Chene field. Like Lake Washington, it produces from Miocene sands surrounding a central salt dome. At December 31, 2013, we had one proved undeveloped location in the Bay de Chene field.

Central Louisiana

Sales and Planned Dispositions. In May 2013, we disposed of our Brookeland field in Texas for net cash proceeds of approximately $6.0 million and the buyer's assumption of our $11.3 million asset retirement obligation. In August 2013, we announced plans to divest our Austin Chalk and Wilcox assets in Louisiana to intensify our focus and build upon the operational success of our assets in South Texas. For further discussion please see the 2014 Strategy and Outlook section in Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

Burr Ferry. The Company has 98,671 net acres in the Burr Ferry field predominately located in Vernon Parish, Louisiana. A majority of this acreage is subject to a joint venture agreement with a large independent oil and gas producer, which terminates mid-year 2014. We entered into this joint venture agreement in 2009 for development and exploitation and hold a 50% working interest in the joint venture. During 2013, the Company participated in drilling two non-operated wells. The reserves are approximately 67% oil and NGLs. We have identified 20 proved undeveloped locations in this field.

Masters Creek. As of December 31, 2013, we owned drilling and production rights in 50,057 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 65% oil and NGLs.

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, 2013, we owned drilling and production rights in 7,327 net acres in this field. Wells drilled in this field are completed in a multiple set of separate sands in the Wilcox formation. In 2013, we drilled one horizontal well in this field. At December 31, 2013, we had 31 proved undeveloped locations in this field.

Other

Four Corners. At December 31, 2013, we had approximately 59,201 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 drilled one exploratory well and completion of the this well is pending until all of the tests, core samples and logs are fully analyzed and an appropriate completion approach can be designed.

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 as of December 31, 2013, 2012 and 2011. The information set forth in the tables regarding reserves is based on proved reserves reports we have prepared. Our Chief Reservoir Engineer, the primary technical person responsible for overseeing the preparation of our 2013 reserves estimates, holds a bachelor's degree in geology, is a member of the Society of Petroleum Engineers and the Society of Professional Well Log Analysts, and has over 25 years of experience in petrophysical analysis, reservoir engineering, and reserves estimation. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, has audited 97%, 96% and 94% of our proved reserves for the years ended December 31, 2013, 2012 and 2011. 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 year's worth of 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 asset team 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. A majority of our asset team reservoir engineers involved in the reserves estimation process have over 10 years reservoir engineering experience. The Chief Reservoir 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, 2013, 2012 and 2011 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 2013 average adjusted prices after differentials for operations were $3.41 per Mcf of natural gas, $104.38 per barrel of oil, and $31.68 per barrel of NGL, compared to $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL at year-end 2012 and $3.89 per Mcf of natural gas, $103.87 per barrel of oil, and $49.55 per barrel of NGL at year-end 2011.

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, 2013, 2012 and 2011. 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 Natural Gas, Oil and NGL Reserves	As of December 31,		
	2013	2012	2011
Natural gas reserves (MMcf):			
Proved developed	197,816	195,643	184,355
Proved undeveloped	617,309	401,926	432,404
Total	815,125	597,569	616,759
Oil reserves (MBbl):			
Proved developed	16,884	17,780	13,840
Proved undeveloped	36,110	25,479	17,091
Total	52,994	43,259	30,931
NGL reserves (MBbl):			
Proved developed	13,059	15,328	11,078
Proved undeveloped	17,320	33,891	14,759
Total	30,379	49,219	25,837
Total Estimated Reserves (MBoe)	219,227	192,073	159,562
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 1,028	$ 1,201	$ 1,075
Proved undeveloped	1,397	1,083	843
PV-10 Value	$ 2,425	$ 2,284	$ 1,918

The PV-10 Values as of December 31, 2013, 2012 and 2011 are net of $87.0 million, $89.6 million, and $75.0 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)	2013	2012	2011
PV-10 Value	$2,425	$2,284	$1,918
Future income taxes (discounted at 10%)	(423)	(412)	(400)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$2,002	$1,872	$1,518

Proved Undeveloped Reserves

The following table sets forth the aging of our proved undeveloped reserves as of December 31, 2013:

Year Added	Volume (MMBoe)	% of PUD Volumes
2013	140.7	90 %
2012	10.4	7 %
2011	0.8	— %
2010	2.4	2 %
2009	0.6	— %
Prior to 2009	1.4	1 %
Total	156.3	100 %

We expect to develop the proved undeveloped reserves listed above, excluding certain Southeast Louisiana reserves noted below, within five years of when they were initially disclosed. Included in the table above are proved undeveloped reserves located in Southeast Louisiana which are older than five years from initial disclosure date, and development is delayed as a result of external factors related to the physical operating conditions in the field. We must prudently wait for down structure wells in the field to water out before up structure locations are drilled to efficiently drain the reservoirs. We believe these conditions qualify these proved undeveloped reserves for an exemption from the five year development rule.

During 2013, we increased our proved undeveloped reserves by 72 MMBoe based on the results of the drilling program conducted during the year, primarily due to new wells drilled in the Fasken Eagle Ford area. We also recorded net downward revisions during the year of 21 MMBoe, which were due to changing economics and performance issues in the Artesia Wells Eagle Ford field and the release of natural gas acreage in our AWP Olmos field. These negative revisions were partially offset by net upward revisions in our other areas. We also incurred approximately $247 million in capital expenditures during the year to convert 21 MMBoe of our December 31, 2012 proved undeveloped reserves to proved developed reserves, primarily in the Artesia Wells and AWP Eagle Ford areas.

The PV-10 Value from our proved undeveloped reserves was $1.4 billion at December 31, 2013, which was approximately 58% of our total PV-10 Value of $2.4 billion. The PV-10 Value of our proved undeveloped reserves, by year of booking, was 81% in 2013, 5% in 2012, 2% in 2011, 7% in 2010, 1% in 2009 and 4% prior to 2009.

Sensitivity of Reserves to Pricing

As of December 31, 2013, a 5% increase in oil and NGL pricing would increase our total estimated proved reserves of 219.2 MMBoe by approximately 0.3 MMBoe, and would increase the PV-10 Value of $2.4 billion by approximately $165 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.5 MMBoe and would decrease the PV-10 Value by approximately $164 million.

As of December 31, 2013, a 5% increase in natural gas pricing would increase our total estimated proved reserves by approximately 0.3 MMBoe and would increase the PV-10 Value by approximately $76 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated proved reserves by approximately 0.4 MMBoe and would decrease the PV-10 Value by approximately $76 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, 2013			
Gross	345	719	1,064
Net	325.1	701.2	1,026.3
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

(1) Excludes 60, 59 and 38 service wells in 2013, 2012 and 2011.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2013:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	—	—	79,818	59,201
Louisiana (1)	125,503	107,936	110,956	90,005
Texas (2)	61,300	59,800	6,800	5,500
Wyoming	—	—	8,957	8,174
Total	186,803	167,736	206,531	162,880

(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 Energy is the fee mineral owner as well as a working interest owner. This acreage included in the above table totals 66,027 gross and 65,905 net undeveloped acres and 20,174 gross and net developed acres. The Company also owns fee mineral interest in approximately 16,295 acres that are currently unleased and not included in the table above. Swift owns a total of 86,201 mineral acres.

(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 37,300 gross and 34,802 net developed acres and 16,500 gross and 10,300 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos, we have 59,900 gross and 48,400 net developed acres and 8,000 gross and 8,000 net undeveloped acres.

As of December 31, 2013, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 2% in 2014, 6% in 2015 and 8% in 2016. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options. The exploration potential of all undeveloped acreage is fully evaluated before expiration. In each fiscal year where undeveloped acreage is subject to expiration our intent is to reduce the expirations through either development or extensions, if we believe it is commercially advantageous to do so.

Drilling and Other Exploratory and Development Activities

The following table sets forth the results of our drilling activities during the years ended December 31, 2013, 2012 and 2011:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2013	Exploratory	1	1	—	1.0	1.0	—
	Development	47	46	1	45.0	44.0	1.0
2012	Exploratory	—	—	—	—	—	—
	Development	71	71	—	66.2	66.2	—
2011	Exploratory	—	—	—	—	—	—
	Development	44	44	—	39.6	39.6	—

Present Activities

As of December 31, 2013, we were in the process of drilling four wells in our South Texas Area, in which we own a 100% working interest. We are also currently expanding and/or upgrading three facilities in South Texas to handle additional production volumes expected to come online in 2014. In the Lake Washington field, we have continued the production optimization program to mitigate natural field declines; involving facility modifications, 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 2013 totaled $11.6 million and ranged from $374 to $1,898 per well per month.

Fixed and Determinable Commitments

As of December 31, 2013, we had natural gas sales commitments to deliver fixed and determinable quantities of natural gas under term contracts in the amount of 3.7 MMBTU. 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, 2013, 2012 and 2011, Shell Oil Company and affiliates accounted for 33%, 46% and 49% of our total oil and gas gross receipts, respectively. BP America accounted for approximately 21% of our total oil and gas gross receipts in 2013 while Southcross Energy accounted for approximately 11% of our total oil and gas gross receipts in 2012. 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 to El Paso's Southern Natural Gas pipeline system (the segment of line into which Swift Energy delivers its gas was sold to High Point Energy, LLC in 2012) and the processing of natural gas is 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. At Fasken, we also have a connection with the Navarro gathering system into which we may deliver natural gas from time to time.

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 Burr Ferry, Masters Creek and South Bearhead Creek fields is sold to various purchasers at prevailing market prices. Our natural gas production from the Burr Ferry 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.

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/A.

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, 2013, 2012 and 2011.

	Year Ended December 31,		
All Fields	2013	2012	2011
Net Sales Volume: (1)			
Oil (MBbls)	3,926	3,774	3,865
Natural Gas Liquids (MBbls)	2,320	1,862	1,362
Natural gas (MMcf) (2)	30,005	33,129	29,237
Total (MBoe)	11,247	11,158	10,100
Average Sales Price: (1)			
Oil (Per Bbl)	$ 103.42	$ 106.17	$ 107.00
Natural Gas Liquids (Per Bbl)	$ 31.39	$ 35.07	$ 52.13
Natural gas (Per Mcf)	$ 3.65	$ 2.66	$ 4.03
Average Production Cost (Per Boe sold) (3)	$ 10.74	$ 10.51	$ 10.38

(1) As described in Note 1A to the consolidated financial statements, adjustments for certain previously identified immaterial accounting errors have been made in this Form 10-K/A. Any effect on the historical net sales volumes and unit sales prices were evaluated and deemed to be immaterial to any period presented and therefore not restated.
(2) Excludes gas consumed in operations that is included in reported production volumes of 2,992 MMcf in 2013, 3,257 MMcf in 2012 and 2,561 MMcf in 2011.
(3) 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 fields with proved reserves greater than 15% of total proved reserves. These fields account for approximately 58% of the Company's proved reserves based on total Boe as of December 31, 2013:

	Year Ended December 31,		
Fasken - Eagle Ford	2013	2012	2011
Net Sales Volume:			
Oil (MBbls)	—	—	—
Natural Gas Liquids (MBbls)	3	1	—
Natural gas (MMcf) (1)	8,571	12,346	8,109
Total (MBoe)	1,432	2,059	1,352
Average Sales Price:			
Oil (Per Bbl)	$—	$—	$—
Natural Gas Liquids (Per Bbl)	$ 35.59	$ 37.85	$—
Natural gas (Per Mcf)	$ 3.52	$ 2.49	$ 3.85
Average Production Cost (Per Boe sold) (2)	$ 4.28	$ 4.09	$ 3.57

(1) Excludes gas consumed in operations that is included in reported production volumes of 246 MMcf in 2013, 655 MMcf in 2012 and 520 MMcf in 2011.

(2) Excludes severance and ad valorem taxes.

AWP Eagle Ford	Year Ended December 31, 2013	2012	2011
Net Sales Volume:			
Oil (MBbls)	1,085	677	400
Natural Gas Liquids (MBbls)	399	296	173
Natural gas (MMcf) (1)	3,260	2,999	3,162
Total (MBoe)	2,027	1,473	1,100
Average Sales Price:			
Oil (Per Bbl)	$ 100.16	$ 101.57	$ 96.36
Natural Gas Liquids (Per Bbl)	$ 30.9	$ 36.53	$ 49.84
Natural gas (Per Mcf)	$ 3.75	$ 2.73	$ 4.05
Average Production Cost (Per Boe sold) (2)	$ 7.31	$ 6.43	$ 6.93

(1) Excludes gas consumed in operations that is included in reported production volumes of 356 MMcf in 2013, 103 MMcf in 2012 and 49 MMcf in 2011.
(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.

At December 31, 2013, we had derivative instruments in place for natural gas, natural gas basis and oil volumes. For additional discussion related to our price-risk management policy, refer to Note 1 of these consolidated financial statements.

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, 2013, we employed 313 persons. None of our employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2013, we occupied approximately 202,355 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a lease expiring February 2015. In February 2014, we amended and extended the lease through November 2015. 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 the prices we receive for our oil and natural gas production. 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).

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 incurred a write-down of the carrying values of our properties in the current year 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. Any capital costs in excess of the ceiling must be permanently written down. We reported a non-cash write-down on a before-tax basis of $46.9 million ($30.0 million after-tax) in the fourth quarter of 2013 on our oil and gas properties. If oil and natural gas prices decline from the prices used in the Ceiling Test, even if only for a short period, it is reasonably possible that additional non-cash write-downs of oil and gas properties would occur in the future. If future capital expenditures out pace future discounted net cash flows in our reserve calculations or if we have significant declines in our oil and natural gas reserves volumes, which also reduces 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 could occur in the future.

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

Unless we successfully replace our reserves, our long-term production will decline, which could result in lower revenues and cash flow. When 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, 2013, approximately 71% 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 development and exploration operations require substantial capital and we may be unable to obtain needed capital at satisfactory levels, which could lead to declines in our cash flow or in our oil and natural gas reserves, or a loss of properties.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. In 2013, our total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $539 million.

We intend to finance our future capital expenditures with cash flow from operations, proceeds from asset dispositions and/or joint ventures and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including:

•our proved reserves;
•the volume of oil and natural gas we are able to produce from existing wells;
•the prices at which our oil and natural gas are sold;
•our ability to acquire, located and produce new reserves; and
•our ability to borrow under our credit facility.

We cannot guarantee that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to declines in our cash flow, or in our oil and natural gas reserves, or in a loss of properties; or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

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 7% of our 2013 reserves and 15% of our 2013 production was located in our Southeast Louisiana core areas. Increased hurricane activity over the past six 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.

A worldwide financial downturn or negative credit market conditions may have lasting effects on our liquidity, business and financial condition that we cannot control or predict.

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.

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.

Our future access to capital could be limited due to tightening credit markets that could affect our ability to fund our future capital projects. 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, 2013 of $265 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 indebtedness may adversely affect operations and reduce our financial flexibility.

As of December 31, 2013, our total debt comprised approximately 52% 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.

Any significant reduction in our borrowing base under our corporate revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

Availability under our corporate revolving credit facility is currently subject to a borrowing base of $450 million. As of December 31, 2013, we had outstanding borrowings of $265 million. We intend to continue borrowing under our revolving credit facility in the future. The borrowing base is subject to periodic redetermination and is based in part on oil, NGL and natural gas prices and the value of properties owned, which could be reduced in the case of asset disposition. Any significant reduction in our borrowing base as a result of such redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations. Further, if the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of such redetermination, we would be required to repay indebtedness in excess of the newly established borrowing base, or we might need to further secure the debt with additional collateral. Our ability to meet any debt obligations in the future depends on our future performance. General business, economic, financial and product pricing conditions, along with other factors, affect our future performance, and many of these factors are beyond our control.

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. Various committees of Congress have been investigating hydraulic fracturing

21

practices and 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. Several states have adopted or are otherwise 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 could significantly increase our operating, capital and compliance costs as well as delay or halt our ability to develop oil and gas reserves.

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.

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 shorter-term hedges, which limits the price protection they provide. Our hedging transactions can consist of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors, calls, swaps, collars and participating collars.

We intend to continue entering 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.

We operate in a litigious environment.

Some of the jurisdictions within which we operate have proven to be litigious environments. Oil and gas companies, such as us, can be involved in various legal proceedings, such as title, royalty, or contractual disputes, in the ordinary course of business. For example, in the state of Louisiana, oil and gas companies are often the target of “legacy lawsuits,” by which a landowner claims that oil and gas operations, often performed many years ago and by another operator, caused pollution or contamination of a property. Various properties we have owned over the past decades potentially expose us to "legacy lawsuit" claims.

Because we maintain a diversified portfolio of assets 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 and/or negative publicity about us and adversely affect the price of our common stock. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

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 relating to environmental protection are costly and stringent.

Our exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing, among other things, the discharge of substances into the environment or otherwise relating to environmental protection. These laws, regulations and related public policy considerations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in order 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 operators. 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, cleanup or other environmental protection requirements could have a material adverse effect on our operations and financial position.

Enactment of legislative or regulatory proposals under consideration could negatively affect our business.

Numerous legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced, or are otherwise under consideration, by Congress and various federal agencies. Among these proposals are: (1) climate change/carbon tax legislation introduced in Congress, and EPA regulations to reduce greenhouse gas emissions; (2) proposals contained in the President's budget, along with legislation introduced in Congress (none of which have passed), to impose new taxes on, or repeal various tax deductions available to, oil and gas producers, such as the current tax deductions for intangible drilling and development costs and qualified tertiary injectant expenses which deductions, if eliminated, could raise the cost of energy production, reduce energy investment and affect the economics of oil and gas exploration and production activities; and (3) legislation previously considered by Congress (but not adopted) that would subject the process of hydraulic fracturing to federal regulation under the Safe Drinking Water Act, and new or anticipated Department of Interior and EPA regulations to impose new and more stringent regulatory requirements on hydraulic fracturing activities, particularly those performed on federal lands, and to require disclosure of the chemicals used in the fracturing process. Any of the foregoing described proposals could affect our operations, and the costs thereof. The trend toward stricter standards, increased oversight and regulation and more extensive permit requirements, along with any future laws and regulations, could result in increased costs or additional operating restrictions which could have an effect on demand for oil and natural gas or prices at which it can be sold. However, until such legislation or regulations are enacted or adopted into law and thereafter implemented, it is not possible to gauge their impact on our future operations or our results of operations and financial condition.

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.

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 currently 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, reduce 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 ("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 including swap clearing and trade execution requirements. New or modified rules, regulations or requirements may increase the cost and availability to our counterparties of their hedging and swap positions which they can make available to us, and may further require the counterparties to our derivative instruments to spin off some of their derivative activities to separate entities which may not be as creditworthy as the current counterparties. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation or post margin collateral. Any changes in the regulations of swaps may result in certain market participants deciding to curtail or cease their derivative activities.

While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed margin rules, remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time. The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, (iii) reduce the availability of derivatives to protect against risks we encounter, and (iv) increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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.

Our business has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain of our exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information and in many other activities related to our business. Our technologies, systems and networks may become the target of cyber attacks or information security breaches that could result in the disruption of our business operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our drilling or production operations.

To date we have not experienced any material losses relating to cyber attacks, however 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 cyber 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.
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.
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.

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/A.
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).
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.

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.

27

PART II

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

Common Stock, 2013 and 2012

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 2013 and 2012 were as follows:

	2013				2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$13.18	$11.81	$10.99	$11.59	$28.30	$15.09	$17.25	$14.28
High	$17.10	$15.63	$13.56	$14.90	$35.00	$30.44	$23.10	$21.07

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 162 stockholders of record as of December 31, 2013.

Stock Repurchase Table

The following table summarizes repurchases of our common stock during the fourth quarter of 2013, all of which were shares withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares:

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)
10/01/13 - 10/31/13 (1)	487	$ 12.85	—	$---
11/01/13 - 11/30/13 (1)	715	$ 13.26	—	—
12/01/13 - 12/31/13 (1)	256	$ 13.00	—	—
Total	1,458	$ 13.08	—	$---

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, 2013 is located in Note 6 to the 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 (Restated)

As discussed in the Explanatory Note to this Form 10-K/A and in Note 1A of the Notes to Consolidated Financial Statements included in Part II. Item 8 of this Form 10-K/A, we are restating our audited consolidated financial statements and related disclosures for the years ended December 31, 2013, 2012 and 2011. The following selected financial data should be read together with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and related notes included elsewhere in this Form 10-K/A. Our historical results are not necessarily indicative of the results that should be expected in the future and the selected financial data is not intended to replace the consolidated financial statements.

(annual data in thousands except per share & well amounts)	December 31, 2013 (As Restated)	2012 (As Restated)	2011 (As Restated)	2010 (As Restated)	2009 (As Restated)
Total Revenues from Continuing Operations (1)	$584,401	$561,486	$597,809	$438,867	$370,445
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$198	$37,773	$131,125	$72,225	$(64,338)
Income (Loss) from Continuing Operations (1)	$(2,442)	$21,701	$82,071	$45,146	$(38,898)
Net Cash Provided by Operating Activities - Continuing Operations	$311,447	$314,606	$373,058	$258,996	$226,176
Per Share and Share Data					
Weighted Average Shares Outstanding	43,331	42,840	42,394	38,300	33,594
Earnings per Share--Basic(1)	$(0.06)	$0.51	$1.94	$1.17	$(1.16)
Earnings per Share--Diluted(1)	$(0.06)	$0.50	$1.91	$1.16	$(1.16)
Shares Outstanding at Year-End	43,402	42,930	42,485	41,999	37,457
Book Value per Share at Year-End	$24.55	$24.52	$23.80	$21.36	$18.62
Market Price					
High	$17.10	$35.00	$47.32	$40.83	$25.61
Low	$10.99	$14.28	$21.81	$24.52	$4.95
Year-End Close	$13.50	$15.39	$29.72	$39.15	$23.96
Assets					
Current Assets	$92,489	$87,005	$334,594	$158,796	$108,600
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$2,588,817	$2,367,954	$1,892,866	$1,599,796	$1,344,772
Total Assets	$2,698,505	$2,473,463	$2,244,012	$1,771,305	$1,463,573
Liabilities					
Current Liabilities	$176,033	$179,412	$216,605	$157,102	$103,604
Long-Term Debt	$1,142,368	$916,934	$719,775	$471,624	$471,397
Total Liabilities	$1,633,155	$1,420,680	$1,232,661	$874,237	$766,294
Stockholders' Equity	$1,065,350	$1,052,783	$1,011,351	$897,068	$697,279
Number of Employees	313	332	309	292	295
Producing Wells					
Swift Operated	1,039	1,069	1,025	1,212	1,146
Outside Operated	25	50	46	119	148
Total Producing Wells	1,064	1,119	1,071	1,331	1,294
Wells Drilled (Gross)	48	71	44	56	20
Proved Reserves					
Natural Gas (Bcf)	815.1	597.6	616.8	423.0	290.6

Oil Reserves (MBoe)	53.0	43.3	30.9	39.3	44.5
NGL Reserves (MBoe)	30.4	49.2	25.8	23.0	20.0
Total Proved Reserves (MMBoe equivalent)	219.2	192.1	159.6	132.8	112.9
Production (MMBoe equivalent)	11.7	11.7	10.5	8.3	9.1
Average Sales Price (2)					
Natural Gas (per Mcf produced)	$3.32	$2.42	$3.70	$3.96	$3.48
Natural Gas Liquids (per barrel)	$31.39	$35.07	$52.13	$42.44	$31.36
Oil (per barrel)	$103.42	$106.17	$107.00	$79.45	$60.07
Boe Equivalent	$50.11	$47.37	$57.22	$52.42	$41.05

(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/A. As described in Note 1A to the consolidated financial statements, adjustments for certain previously identified immaterial accounting errors have been made in this Form 10-K/A. Any effect on the historical unit sales prices were evaluated and deemed to be immaterial to any period presented and therefore not restated.

(in thousands except per share amounts)	December 31, 2013 (As Reported)	(Adjustments)	(As Restated)	December 31, 2012 (As Reported)	(Adjustments)	(As Restated)
Total Revenues from Continuing Operations (1)	$587,713	$ (3,312)	$584,401	$557,290	$ 4,196	$561,486
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$(25,805)	$ 26,003	$198	$36,578	$ 1,195	$37,773
Income (Loss) from Continuing Operations (1)	$(19,032)	$ 16,590	$(2,442)	$20,939	$ 762	$21,701
Net Cash Provided by Operating Activities - Continuing Operations	$311,447	$ —	$311,447	$314,606	$ —	$314,606
Per Share and Share Data						
Weighted Average Shares Outstanding	43,331	—	43,331	42,840	—	42,840
Earnings per Share--Basic(1)	$(0.44)	$ 0.38	$(0.06)	$0.49	$ 0.02	$0.51
Earnings per Share--Diluted(1)	$(0.44)	$ 0.38	$(0.06)	$0.48	$ 0.02	$0.50
Shares Outstanding at Year-End	43,402	—	43,402	42,930	—	42,930
Book Value per Share at Year-End	$23.81	$ 0.74	$24.55	$24.15	$ 0.37	$24.52
Assets						
Current Assets	$86,748	$ 5,741	$92,489	$80,537	$ 6,468	$87,005
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$2,539,646	$ 49,171	$2,588,817	$2,345,020	$ 22,934	$2,367,954
Total Assets	$2,643,593	$ 54,912	$2,698,505	$2,444,061	$ 29,402	$2,473,463
Liabilities						
Current Liabilities	$177,076	$ (1,043)	$176,033	$177,480	$ 1,932	$179,412
Long-Term Debt	$1,142,368	$ —	$1,142,368	$916,934	$ —	$916,934
Total Liabilities	$1,610,377	$ 22,778	$1,633,155	$1,407,201	$ 13,479	$1,420,680
Stockholders' Equity	$1,033,216	$ 32,134	$1,065,350	$1,036,860	$ 15,923	$1,052,783

(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.

(in thousands except per share amounts)	December 31, 2011 (As Reported)	(Adjustments)	(As Restated)	December 31, 2010 (As Reported)	(Adjustments)	(As Restated)
Total Revenues from Continuing Operations (1)	$599,131	$ (1,322)	$597,809	$438,429	$ 438	$438,867
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$135,104	$ (3,979)	$131,125	$74,308	$ (2,083)	$72,225
Income (Loss) from Continuing Operations (1)	$84,610	$ (2,539)	$82,071	$46,475	$ (1,329)	$45,146

Net Cash Provided by Operating Activities - Continuing Operations	$373,058	$ —	$373,058	$258,996	$ —	$258,996
Per Share and Share Data						
Weighted Average Shares Outstanding	42,394	—	42,394	38,300	—	38,300
Earnings per Share--Basic(1)	$2.00	$ (0.06)	$1.94	$1.21	$ (0.04)	$1.17
Earnings per Share--Diluted(1)	$1.97	$ (0.06)	$1.91	$1.20	$ (0.04)	$1.16
Shares Outstanding at Year-End	42,485	—	42,485	41,999	—	41,999
Book Value per Share at Year-End	$23.46	$ 0.34	$23.80	$20.95	$ 0.41	$21.36
Assets						
Current Assets	$332,119	$ 2,475	$334,594	$158,358	$ 438	$158,796
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,867,766	$ 25,100	$1,892,866	$1,572,845	$ 26,951	$1,599,796
Total Assets	$2,216,437	$ 27,575	$2,244,012	$1,743,916	$ 27,389	$1,771,305
Liabilities						
Current Liabilities	$215,762	$ 843	$216,605	$156,735	$ 367	$157,102
Long-Term Debt	$719,775	$ —	$719,775	$471,624	$ —	$471,624
Total Liabilities	$1,219,928	$ 12,733	$1,232,661	$863,899	$ 10,338	$874,237
Stockholders' Equity	$996,509	$ 14,842	$1,011,351	$880,017	$ 17,051	$897,068

(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.

(in thousands except per share amounts)	December 31, 2009 (As Reported)	(Adjustments)	(As Restated)
Total Revenues from Continuing Operations (1)	$370,445	$ —	$370,445
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$(64,617)	$ 279	$(64,338)
Income (Loss) from Continuing Operations (1)	$(39,076)	$ 178	$(38,898)
Net Cash Provided by Operating Activities - Continuing Operations	$226,176	$ —	$226,176
Per Share and Share Data			
Weighted Average Shares Outstanding	33,594	—	33,594
Earnings per Share--Basic(1)	$(1.16)	$ —	$(1.16)
Earnings per Share--Diluted(1)	$(1.16)	$ —	$(1.16)
Shares Outstanding at Year-End	37,457	—	37,457
Book Value per Share at Year-End	$18.12	$ 0.5	$18.62
Assets			
Current Assets	$108,600	$ —	$108,600
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,315,964	$ 28,808	$1,344,772
Total Assets	$1,434,765	$ 28,808	$1,463,573
Liabilities			
Current Liabilities	$103,604	$ —	$103,604
Long-Term Debt	$471,397	$ —	$471,397
Total Liabilities	$755,866	$ 10,428	$766,294
Stockholders' Equity	$678,899	$ 18,380	$697,279

(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.

Table of Contents

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, 2013, 2012 and 2011 included in this report. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management's Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand operations discontinued since late 2007. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 38 of this report.

Restatement

As discussed in the Explanatory Note to this Form 10-K/A and in Note 1A of the Notes to Consolidated Financial Statements included in Part II. Item 8 of this Form 10-K/A, we are restating our audited consolidated financial statements and related disclosures for the years ended December 31, 2013, 2012 and 2011. The following discussion and analysis of our financial condition and results of operations incorporates the restated amounts. For this reason, the data set forth in this Item 7 may not be comparable to the discussion and data in our previously filed Annual Report on Form 10-K for the year ended December 31, 2013.

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 hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development and are one of the largest producers of crude oil in the state of Louisiana. Oil production accounted for 33% of our 2013 production and 69% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 53% of our 2013 production and 81% of our oil and gas sales. In recent periods, 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.

2013 Activities

- Production: Our production volumes increased less than 1% in 2013 when compared to volumes in 2012 as oil volumes increased by 4%, NGL volumes increased by 25% and natural gas production volumes decreased by 9%. The increase in oil volumes was from our South Texas area, primarily offset by declines in our Southeast Louisiana area. The changes in both NGL and natural gas volumes were primarily from our South Texas area.

- Pricing: Driven by higher prices for natural gas, our weighted average sales price in 2013 increased by 6% when compared to our weighted average sales price 2012. Natural gas prices increased 37%, oil prices decreased 3%, and NGL prices decreased 10% when compared to 2012.

- Cash provided by operating activities: For 2013, our cash provided by operating activities of $311.4 million was a 1% decrease from 2012 levels, due primarily to working capital changes during 2013.

- Available liquidity: At December 31, 2013, we had $265.0 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount under the credit facility is $450.0 million, which provides us with approximately $185 million of liquidity. We plan to utilize amounts received from asset sales and joint ventures entered into during 2014 to strengthen our balance sheet, enhance liquidity, and fund a portion of our 2014 capital expenditures. The completion of these transactions will affect our 2014 capital expenditures as we align our capital expenditures with our expected cash flows.

• 2013 capital expenditures: Our capital expenditures on a cash flow basis were $540.4 million in 2013 compared to $757.8 million spent in 2012. The expenditures in both years were mainly due to drilling and completion activity in our South Texas core region. In 2013 we drilled 14 wells in our Artesia Wells Eagle Ford field, 20 wells in our AWP Eagle Ford field, three wells in our AWP Olmos field and five wells in our Fasken Eagle Ford field, which helped us evaluate and maintain our acreage positions in those areas. In Southeast Louisiana we drilled two wells at Lake Washington, one of which was a dry hole, and in Central Louisiana we drilled two non-operated wells in our Burr Ferry field and one operated well in our South Bearhead Creek field. We also drilled our first well in the Niobrara formation of La Plata County, Colorado. These expenditures were funded by $311.4 million of cash provided by operating activities and the remainder through borrowings under our credit facility.

Table of Contents

- Artesia Wells Performance and Economic Issues: In the condensate window of our Artesia Wells field, we experienced decreases in expected liquids production as our wells matured, which we believe may partially be due to retrograde condensation. This occurs when condensate turns into liquid form within the reservoir as the pressure in the reservoir decreases below dew point pressure. This retrograde condensate does not flow out of the reservoir which reduces our production rates and ultimate EURs. We started experiencing this issue during late 2013 and are still assessing the situation. Based on our recent experience we decided to remove 32 proved undeveloped locations from our proved reserves (in the southern and western areas) as we currently are not planning to develop them in the next five years. The proved undeveloped locations in the liquid-yielding northern area are economic and remain in our reserves as we do plan to drill these locations within the next five years.

2014 Strategy and Outlook

- 2014 Planned Capital Expenditures: Our 2014 planned capital expenditures are $300 to $350 million. We currently plan to fund our 2014 capital expenditures with our operating cash flow and potential line of credit borrowings, plus any proceeds from the disposition of all or a portion of our Central Louisiana assets (see below) and/or proceeds from joint ventures we enter into involving our properties in the Fasken Eagle Ford area (see below). If we do not receive such disposition or joint venture proceeds, we will align our capital spending with our expected cash flows. These amounts are flexible and will be adjusted based on the timing of any announced transactions and market fundamentals. For 2014, the Company is targeting production levels of 11.3 to 11.8 MMBoe.

- Central Louisiana Property Disposition: We are currently negotiating with prospective buyers to sell some or all of our Austin Chalk and Wilcox assets in Central Louisiana in order to focus our spending on our South Texas properties. We expect to finalize an agreement by the end of the second quarter. These Central Louisiana assets include approximately 86,000 mineral acres and three producing oil and natural gas fields: Burr Ferry, Masters Creek, and South Bearhead Creek.

- Pursuit of Eagle Ford Joint Venture: We are currently negotiating with prospective partners regarding a joint venture arrangement for a portion of our natural gas properties in the Eagle Ford area, principally our natural gas properties in the Fasken area. Entering into a joint venture agreement would accelerate drilling and development, monetize a portion of those asset values, diversify our risk profile and possibly free up capital dollars for other purposes. We are targeting completion of this initiative by the end of the second quarter of 2014.

- Reduced Spending for 2014: We expect a reduction in capital spending targets for 2014 to levels more in line with our internally generated cash flow and disposition and/or joint venture proceeds. Our priorities are financial discipline first and growth second. We expect to continue focusing on South Texas production and reserves, while maintaining a stronger balance sheet and enhancing liquidity. We are also taking current steps to reduce our future operating and overhead costs through a number of initiatives, including reducing personnel in conjunction with any asset dispositions and alignment of our other expenses, including cancellation of a new lease for future corporate office space, which will allow us to seek out more efficient and cost effective space.

- Operating improvements through new Eagle Ford drilling and completion technology: Our South Texas drilling activities continue to benefit from optimized well design as we are drilling longer laterals in our horizontal wells and performing more frac stages per well. When we began drilling in the Eagle Ford, our average lateral length was approximately 3,000 feet, and we performed up to nine frac stages per well. Our current process allows us to drill laterals of over 6,000 feet and complete 20 or more frac stages per well. We have observed a high correlation between the lateral length and number of frac stages in horizontal Eagle Ford wells, along with improved initial performance and long-term cumulative production. Additionally, as several of our peers have also announced, we are now increasing the number of frac stages per 1,000 feet of lateral length and using greater amounts of sand with each frac as we believe these changes could bring further improvement in our results.

- Improved performance of Eagle Ford shale assets through reduction in per well costs: We have seen improved performance this year in our initial production (IP) rates for Eagle Ford wells and have also seen our per well drilling and completion costs come down from those experienced in the prior year. Part of our goals for 2013 was to improve IP rates by 10% for these wells and reduce the average cost per well by 10%. Our IP rates increased over 10% in each area - Fasken was 62% higher than our 2012 model IP, Artesia Wells oil and condensate increased 44%, and AWP oil increased 33%. Overall our drilling and completion costs combined decreased by more than 10%, with drilling costs down 17% and completion costs down 9%. With faster drilling times, we are currently able to drill more wells per rig than previously expected. We have also

Table of Contents

experienced efficiency gains in our hydraulic fracturing activities (fracs), which enable us to perform more frac stages per month, lower the overall frac cost per stage and achieve better overall results. We believe that progression along this technology learning curve is important to improving performance and reducing costs. As an example, we have had excellent production results from the last two wells completed in our Fasken area during December 2013 which have been the most prolific wells in that area. While no two wells are the same, we have seen significant increases in 30, 60, 90, and 120 day oil recoveries from our more recent vintage wells.

- Advances in 3D Geoscience technologies allow more targeted drilling: We are utilizing state of the art geoscience technologies to improve our lateral placements and completion design in the Eagle Ford and to better define our undeveloped resource potential in Lake Washington. In the Eagle Ford, GEOFRAC logging of the horizontal well bore has led to more effective placement of frac stages and also assisted in identifying sections of rock that are not ideal for stimulation, affording opportunities to eliminate potentially non-productive frac stages. We have been able to utilize our 3D seismic in this area, along with the analysis of cores and well logs, to identify a narrow high quality interval of the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our well results. In our Lake Washington area, we have applied new state of the art tools to better define the undeveloped resources in the field. We will be reprocessing our proprietary 3D seismic data with the help of these new tools and expect to identify additional unevaluated development potential in this field.

- Ability to capitalize on increased natural gas prices in the future: Although current natural gas prices are lower than historical highs, prices have improved significantly from the lows seen in the last several years. With increasing demand, including the volume of LNG available for export increasing over the next several years, we believe natural gas prices will increase from current levels and that selected natural gas properties can be economically developed in today’s market, although much of the potential for natural gas development will require higher prices. Our Fasken properties in Webb County, which include some of the best Eagle Ford rock in South Texas as defined by porosity, total organic content and other geologic and petrophysical qualities, can be economically developed today, while such potential natural gas resources as those in our South AWP area in McMullen County require a higher price environment to provide adequate economic returns. Our strategy includes a balanced approach to oil and natural gas, and as such we plan to continue some development on our prolific natural gas properties, such as Fasken.

Table of Contents

Results of Operations

Revenues — Years Ended December 31, 2013, 2012 and 2011

2013 - Our revenues in 2013 increased by 4% compared to revenues in 2012, due to higher natural gas pricing and higher oil and NGL production, partially offset by lower oil and NGL pricing and lower natural gas production. Average oil prices we received were 3% lower than those received during 2012, while natural gas prices were 37% higher, and NGL prices were 10% lower.

2012 - Our revenues in 2012 decreased by 6% 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.

Crude oil production was 33%, 32% and 37% of our production volumes while crude oil sales were 69%, 72% and 69% of oil and gas sales for the years ended December 31, 2013, 2012 and 2011, respectively. Natural gas production was 47%, 52% and 50% of our production volumes while natural gas sales were 19%, 16% and 20% of oil and gas sales for the years ended December 31, 2013, 2012 and 2011, 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, 2013, 2012 and 2011:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2013	2012	2011	2013	2012	2011
Southeast Louisiana	$ 168.0	$ 215.0	$ 287.4	1,797	2,227	3,164
South Texas	360.2	290.1	224.2	9,009		