SWIFT ENERGY CO
Form 10-K
March 02, 2015

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2014

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.
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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, 2014, the last business day of June 2014, was approximately $551,832,992.

The number of shares of common stock outstanding as of January 31, 2015 was 44,006,995.

Documents Incorporated by Reference

Proxy Statement for the Annual Meeting of Shareholders to be held May 19, 2015	Part III, Items 10, 11, 12, 13 and 14

2

Form 10-K
Swift Energy Company and Subsidiaries

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 19, 2015

Items 1 and 2. Business and Properties

As used in this Annual Report on Form 10-K, unless the context otherwise requires or indicates, references to "Swift Energy," "the Company," "we," "our," "ours" and "us" refer to Swift Energy Company. See pages 21 and 22 for explanations o abbreviations and terms used herein.

Overview

Swift Energy Company, a Texas corporation founded in 1979, is an independent oil and gas company engaged in developing, exploring, acquiring, and operating oil and gas properties. Our primary focus is on the Eagle Ford trend of South Texas and, to a lesser extent, the onshore and inland waters of Louisiana. We operate approximately 99% of the properties that we own and we have implemented leading edge technologies to maximize the discovery, development and production of our potential reserve base in the Eagle Ford and other areas where we operate. As a result of the significant resource potential from our properties in the Eagle Ford, we plan to invest a significant portion from our total 2015 planned capital expenditures of $110 to $125 million, in this area.

At December 31, 2014, we had estimated proved reserves of 193.8 MMBoe with a PV-10 Value of $1.9 billion (PV-10 Value is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" of this Form 10-K for a reconciliation of this non-GAAP measure to the closest GAAP measure). Our total proved reserves at December 31, 2014 were approximately 26% crude oil, 59% natural gas, and 15% NGLs while 34% of our total proved reserves were developed. Approximately 81% of our proved reserves are located in Texas with the remainder in Louisiana.

Business Strategy

Our primary business strategy is to increase our reserves, production and cash flows at an attractive rate of return on invested capital. Our business strategy is primarily focused on exploiting our unconventional reserves from the Eagle Ford and, to a lesser extent, exploiting our more conventional reserves in Louisiana.

- Develop our Eagle Ford shale resource play. We have a long successful history operating oil and gas wells and finding reserves in South Texas. We believe our current acreage position in the Eagle Ford provides us the ability to continue to increase reserves and production at competitive costs and at attractive rates of return. During 2014, we drilled 36 horizontal Eagle Ford wells. Focusing on the Eagle Ford play allows us to use our operating, technical and regional expertise to interpret geological and operating trends, enhance production rates and maximize well recovery. We are focused on enhancing the value of our assets through operating improvements that utilize cost-effective technology to locate the highest quality intervals to drill and complete oil and gas wells. For instance, we are using proprietary 3D seismic techniques to identify a narrow high quality interval of the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our recent well results.

- Operate our properties as a low-cost producer. We believe our concentrated acreage position in the Eagle Ford and our experience as an operator of virtually all of our properties enables us to apply drilling and completion techniques and economies of scale that improve the returns that we are able to achieve. Operating control allows us to better manage timing and risk as well as the cost of infrastructure, drilling and ongoing operations. We generally drill multiple wells from a single pad, which reduces facilities costs and surface impact. Our operational control is critical to us being able to transfer successful drilling and completion techniques from one field to another.

- Acquire strategic and complementary assets. We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects in our existing core area in the Eagle Ford. We focus particularly on opportunities where we believe our operational efficiency, reservoir management and geological expertise in unconventional oil and gas properties will enhance value and performance.

- Efficiently finance growth. During 2014, we closed a transaction with Saka Energi to develop 8,300 acres of natural gas Eagle Ford shale properties in our Fasken area. Saka Energi purchased a 36% full participating interest in the properties for $175 million. The proceeds from the transaction were used to pay down our credit facility which were partially offset by subsequent additional borrowings against the credit facility to fund development expenditures.

Competitive Strengths

Premier Eagle Ford Operator

We have operational history, experience and success in South Texas that is unmatched by many other operators. We first acquired producing properties in our AWP field in 1989, added adjacent acreage shortly thereafter and launched our first aggressive drilling program in 1994. This area has remained a cornerstone of our operations as we have pursued other opportunities. 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. Almost all of our existing South Texas interest overlays portions of the Eagle Ford shale play which is being developed through the combination of horizontal drilling and multi-stage fracture stimulation completion techniques. 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 2014, we successfully drilled 36 horizontal wells in our South Texas area using this technology.

High Quality Reserve Base

We have grown our proved reserves from 112.9 MMBoe to 193.8 MMBoe over the five-year period ended December 31, 2014. Over the same period, our annual production has grown from 8.3 MMBoe to 12.4 MMBoe. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our core areas. 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. We have replaced approximately 248% of our production on average over the last five years with our new reserves.

Experienced Technical Team

We employ 56 oil and gas technical professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for an average of approximately 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.

Operating Areas

Our operations are primarily focused in three core areas identified as South Texas, Southeast Louisiana and Central Louisiana. The following table sets forth information regarding our 2014 year-end proved reserves of 193.8 MMBoe and production of 12.4 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		Total Production (MBoe)
Artesia Wells	8.4	14.0	22.4	11.5	%	53.3	%	1,786
AWP	26.5	41.2	67.7	34.9	%	54.8	%	4,636
Fasken	18.4	45.6	64.0	33.0	%	—	%	3,565
Other South Texas	3.5	—	3.5	1.8	%	53.1	%	252
Total South Texas	56.8	100.8	157.6	81.2	%			10,239

Southeast Louisiana	5.7	5.9	11.6	6.0	%	93.6	%	1,459
Central Louisiana	3.7	20.8	24.5	12.7	%	71.9	%	656
Other	0.1	—	0.1	0.1	%	0.5	%	33
Total	66.3	127.5	193.8	100.0	%	40.9	%	12,387

South Texas

AWP. During 2014, the Company drilled 20 wells in AWP targeting the Eagle Ford formation. All wells in this field were drilled and are operated by Swift Energy. Our proved reserves in this formation are 41% natural gas, 22% NGLs, and 36% oil on a Boe basis. As of December 31, 2014 we had identified 120 proved undeveloped locations.

In the Olmos formation, the wells are operated and owned by Swift Energy and our reserves in this formation are approximately 58% natural gas, 31% NGLs, and 11% oil on a Boe basis. At December 31, 2014, we had seven proved undeveloped locations in the Olmos.

Artesia Wells. Our December 31, 2014 proved reserves in this formation are 47% natural gas, 35% NGLs, and 18% oil on a Boe basis. At December 31, 2014, we had identified 31 proved undeveloped locations.

Fasken. During 2014, the Company drilled 16 wells in Fasken targeting the Eagle Ford formation. All wells in this field were drilled and are operated by Swift Energy. Our reserves in this Eagle Ford formation are 100% natural gas. At December 31, 2014, we had identified 45 proved undeveloped locations.

On July 15, 2014, we closed a transaction with Saka Energi to fully develop 8,300 acres of natural gas Eagle Ford shale properties in our Fasken field. Saka Energi purchased a 36% full participating interest in the properties. Refer to Note 8 of the consolidated financial statements in this Form 10-K for further discussion of this transaction.

Southeast Louisiana

Lake Washington. 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 which are heavily faulted, thereby creating a large number of potential hydrocarbon traps. Approximately 97% of our proved reserves in this field consisted of oil and NGLs which are gathered to several platforms located in water depths from 2 to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2014 we did not drill any wells in Lake Washington, but in our 2014 production optimization program we performed 23 recompletions and numerous production enhancement operations including sliding sleeve changes, gas lift modifications and well stimulations. At December 31, 2014, we had 26 proved undeveloped locations in this field.

Bay de Chene. The Bay de Chene field is located approximately 25 miles from the Lake Washington field and produces from Miocene sands surrounding a central salt dome. At December 31, 2014, we had one proved undeveloped location in the Bay de Chene field.

Central Louisiana

Burr Ferry. This field is predominately located in Vernon Parish, Louisiana. During 2014 our joint venture agreement for a portion of the field expired and was not renewed. The reserves are approximately 59% oil and NGLs. We have identified 23 proved undeveloped locations in this field.

Masters Creek. Located in Vernon Parish and Rapides Parish, Louisiana, this field produces oil and natural gas from the Austin Chalk formation. The reserves are approximately 61% oil and NGLs.

South Bearhead Creek. This field is located approximately 50 miles south of our Masters Creek field and is a large east-west trending anticline closure. Wells drilled in this field are completed in a multiple set of separate sands in the Wilcox formation. At December 31, 2014, we had 49 proved undeveloped locations in this field.

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, 2014, 2013 and 2012. 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 2014 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% of our proved reserves for the years ended December 31, 2014 and 2013 and 96% of our proved reserves for the year ended December 31, 2012. The audit by H.J. Gruy and Associates, Inc. conformed to the meaning of the term “reserves audit” as presented in Regulation S-K, Item 1202. The technical person at H.J. Gruy and Associates, Inc. primarily responsible for overseeing the audit, is a Licensed Professional Engineer, holds a degree in petroleum engineering, is past Chairman of the Gulf Coast Section of the Society of Petroleum Engineers, is past President of the Society of Petroleum Evaluation Engineers and has over 30 years of experience overseeing reserves audits. Based on their audit, 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 members of the reserves and evaluation department who report to the Chief Reservoir Engineer as well as 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 of 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, 2014, 2013 and 2012 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 2014 average adjusted prices after differentials for operations were $4.32 per Mcf of natural gas, $93.64 per barrel of oil, and $33.00 per barrel of NGL, compared to $3.41 per Mcf of natural gas, $104.38 per barrel of oil, and $31.68 per barrel of NGL for 2013 and $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL for 2012.

The 2014 prices noted above do not fully reflect significant crude oil and natural gas price declines in late 2014 or early 2015 when these commodity prices dropped rapidly, declining to below $45 per barrel of oil (as measured using the WTI crude oil price and below $3.00 per Mcf of natural gas (as measured using the Henry Hub natural gas spot price).

7

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, 2014, 2013 and 2012. 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,		
	2014	2013	2012
Natural gas reserves (MMcf):			
Proved developed	232,807	197,816	195,643
Proved undeveloped	453,940	617,309	401,926
Total	686,747	815,125	597,569
Oil reserves (MBbl):			
Proved developed	14,989	16,884	17,780
Proved undeveloped	34,717	36,110	25,479
Total	49,706	52,994	43,259
NGL reserves (MBbl):			
Proved developed	12,495	13,059	15,328
Proved undeveloped	17,168	17,320	33,891
Total	29,663	30,379	49,219
Total Estimated Reserves (MBoe) (1)	193,826	219,227	192,073
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$954	$1,028	$1,201
Proved undeveloped	990	1,397	1,083
PV-10 Value (2)	$1,944	$2,425	$2,284

(1) The 2014 reserve volumes exclude natural gas consumed in operations. For additional discussion of this methodology refer to the Supplementary Reserves Information of this Form 10-K.
(2) The PV-10 Values as of December 31, 2014, 2013 and 2012 are net of $85.5 million, $87.0 million, and $89.6 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)	2014	2013	2012
PV-10 Value	$1,944	$2,425	$2,284
Future income taxes (discounted at 10%)	(292)	(423)	(412)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and natural gas reserves	$1,652	$2,002	$1,872

Proved Undeveloped Reserves

The following table sets forth the aging of our proved undeveloped reserves as of December 31, 2014:

Year Added	Volume (MMBoe)	% of PUD Volumes
2014	22.0	17 %
2013	93.4	73 %
2012	11.4	9 %
2011	0.7	1 %
2010	0.0	— %
Total	127.5	100 %

During 2014, our proved undeveloped reserves decreased by approximately 23 MMBoe due to the sale of our Fasken properties, which is discussed further in Note 8 of the consolidated financial statements in this Form 10-K. We also incurred approximately $226 million in capital expenditures during the year which resulted in the conversion of 21 MMBoe of our December 31, 2013 proved undeveloped reserves to proved developed reserves in the Fasken and AWP fields. These reductions were partially offset by the addition of approximately 15 MMBoe in proved undeveloped reserves in the AWP area based on the results of our drilling program.

The PV-10 Value from our proved undeveloped reserves was $1.0 billion at December 31, 2014, which was approximately 51% of our total PV-10 Value of $1.9 billion. The PV-10 Value of our proved undeveloped reserves, by year of booking, was 14% in 2014, 73% in 2013, 11% in 2012 and 2% in 2011.

Sensitivity of Reserves to Pricing

As of December 31, 2014, a 5% increase in oil and NGL pricing would increase our total estimated proved reserves of 193.8 MMBoe by approximately 0.4 MMBoe, and would increase the PV-10 Value of $1.9 billion by approximately $146 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.4 MMBoe and would decrease the PV-10 Value by approximately $143 million.

As of December 31, 2014, a 5% increase in natural gas pricing would increase our total estimated proved reserves by approximately 0.2 MMBoe and would increase the PV-10 Value by approximately $75 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated proved reserves by approximately 0.2 MMBoe and would decrease the PV-10 Value by approximately $72 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, 2014			
Gross	348	717	1,065
Net	330.3	673.9	1,004.2
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

(1) Excludes 49, 60 and 59 service wells in 2014, 2013 and 2012.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2014:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Colorado	—	—	76,265	56,537
Louisiana (1)	116,891	103,571	99,628	79,772
Texas (2)	68,518	64,147	24,867	22,755
Wyoming	—	—	3,797	1,602
Total	185,409	167,718	204,557	160,666

(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 66,073 gross and 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 86,247 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 36,316 gross and 29,706 net developed acres and 34,455 gross and 27,010 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos, we have 49,917 gross and 46,518 net developed acres and 24,526 gross and 21,940 net undeveloped acres.

As of December 31, 2014, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 10% in 2015, 4% in 2016 and 11% in 2017. 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, 2014, 2013 and 2012:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2014	Exploratory	—	—	—	—	—	—
	Development	36	36	—	31.5	31.5	—
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	—

Present Activities

As of December 31, 2014, we were in the process of drilling five development wells in our South Texas Area, of which four wells were in the Fasken field with a 64% working interest and one well was in the AWP field with a 100% working interest.

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 2014 totaled $12.7 million and ranged from $383 to $1,945 per well per month.

Fixed and Determinable Commitments

As of December 31, 2014, we had natural gas sales commitments to deliver fixed and determinable quantities of natural gas under term contracts in the amount of 18.3 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, 2014, 2013 and 2012, Shell Oil Company and affiliates accounted for 21%, 33% and 46% of our total oil and gas gross receipts, respectively. Kinder Morgan and Plains Marketing accounting for approximately 20% and 11% of our total oil and gas gross receipts in 2014, 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.

We have gas processing and gathering agreements with Southcross Energy for a majority of our natural gas production in the AWP area. Other gas production in the AWP area is processed or transported under arrangements with DCP Midstream and Enterprise. Oil production is transported to market by truck and sold at prevailing market prices.

We have a gathering agreement with Howard Energy 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. 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. Natural gas in the area can also be delivered to the Atlas system for processing and transportation to downstream markets. In the Artesia Wells area, our oil production is sold at prevailing market prices and transported to market by truck.

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 and the processing of natural gas occurs at the Toca Plant.

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. South Bearhead Creek natural gas production is sold into the interstate market on Trunkline Gas Company's pipeline 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.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil, NGL and natural gas production for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
All Fields	2014	2013	2012
Net Sales Volume:			
Oil (MBbls)	3,511	3,926	3,774
Natural Gas Liquids (MBbls)	1,812	2,320	1,862
Natural gas (MMcf) (1)	38,499	29,672	33,462
Total (MBoe)	11,740	11,191	11,213
Average Sales Price:			
Oil (Per Bbl)	$ 92.74	$ 103.42	$ 106.17
Natural Gas Liquids (Per Bbl)	$ 31.83	$ 31.39	$ 35.07
Natural gas (Per Mcf)	$ 4.27	$ 3.70	$ 2.64
Average Production Cost (Per Boe sold) (2)	$ 9.74	$ 11.08	$ 10.30

(1) Excludes natural gas consumed in operations that is included in reported production volumes of 3,884 MMcf in 2014, 3,325 MMcf in 2013 and 2,924 MMcf in 2012.
(2) Average production cost includes transportation and gas processing costs but 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 68% of the Company's proved reserves based on total Boe as of December 31, 2014:

	Year Ended December 31,		
Fasken	2014	2013	2012
Net Sales Volume:			
Oil (MBbls)	—	—	—
Natural Gas Liquids (MBbls)	3	3	1
Natural gas (MMcf) (1)	20,738	8,457	12,460
Total (MBoe)	3,459	1,413	2,078
Average Sales Price:			
Oil (Per Bbl)	$—	$—	$—
Natural Gas Liquids (Per Bbl)	$32.44	$35.59	$37.85
Natural gas (Per Mcf)	$4.20	$3.57	$2.47
Average Production Cost (Per Boe sold) (2)	$3.77	$4.34	$4.06

(1) Excludes natural gas consumed in operations that is included in reported production volumes of 636 MMcf in 2014, 360 MMcf in 2013 and 541 MMcf in 2012.
(2) Average production cost includes transportation and gas processing costs but excludes severance and ad valorem taxes.

	Year Ended December 31,		
AWP	2014	2013	2012
Net Sales Volume:			
Oil (MBbls)	1,655	1,421	1,167
Natural Gas Liquids (MBbls)	968	1,068	1,139
Natural gas (MMcf) (1)	10,753	10,359	12,910
Total (MBoe) (3)	4,415	4,216	4,458
Average Sales Price:			
Oil (Per Bbl)	$89.86	$100.42	$101.86
Natural Gas Liquids (Per Bbl)	$30.72	$30.72	$34.58
Natural gas (Per Mcf)	$4.31	$3.72	$2.58
Average Production Cost (Per Boe sold) (2)	$8.98	$10.50	$9.11

(1) Excludes natural gas consumed in operations that is included in reported production volumes of 1,327 MMcf in 2014, 1,097 MMcf in 2013 and 993 MMcf in 2012.
(2) Average production cost includes transportation and gas processing costs but excludes severance and ad valorem taxes.
(3) AWP Eagle Ford sales accounted for approximately 67%, 48% and 33% of total BOE sales in 2014, 2013 and 2012, respectively.

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. We maintain comprehensive insurance coverage, including general liability insurance, operators extra expense insurance, and property damage insurance. Our standing Insurable Risk Advisory Team, which includes individuals from operations, drilling, facilities, 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. Refer to “Item 1A. Risk Factors” of this Form 10-K for more details and for discussion of other risks.

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. For additional discussion related to our price-risk policy, refer to Note 1 of the consolidated financial statements in this Form 10-K.

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

As of December 31, 2014, the Company employed 294 people. Subsequent to December 31, 2014 the company reduced personnel by approximately 20% in connection with the lower commodity pricing environment. None of our employees were represented by a union and relations with employees are considered to be good.

Facilities

At December 31, 2014, we occupied approximately 147,000 square feet of office space at 16825 Northchase Drive, Houston, Texas. In January of 2015 we signed a new lease agreement commencing on March 1, 2015 for approximately 117,000 square feet of office space at 17001 Northchase Drive, Houston, Texas. For discussion regarding the term and obligations of this lease refer to Note 5 of the consolidated financial statements in this Form 10-K.

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 the major risks relating to our business activities:

Oil and natural gas prices are volatile. Commodity prices have dropped substantially and rapidly since September 2014. Continued low prices or their further downward movement would adversely affect our liquidity, operating results, financial condition, cash flows and growth prospects.

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 have dropped precipitously over the past six months, especially in the last quarter of 2014 and first quarter of 2015.

Continued low price levels or further decreases in price levels for either oil or natural gas would negatively affect us in several ways, including:

- our cash flow would be reduced, decreasing funds available for capital expenditures;
- certain reserves would no longer be economic to produce, leading to both lower cash flow and lower proved reserves;
- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserves values, reducing our liquidity and possibly requiring mandatory loan repayments; and
- such a reduction may result in a downward adjustment to our estimated proved reserves, and require write-downs of our oil and gas properties.

The effects of current or lower oil and gas prices could require us to amend financial covenants in our credit facility.

Our revolving credit facility contains both an adjusted working capital ratio covenant and an interest coverage ratio covenant (as defined in our Credit Agreement in exhibit 10.8 to this Form 10-K; see also Note 4 of the consolidated financial statements in this Form 10-K for further discussion of these ratios). Continuation of low oil prices or their further deterioration could significantly reduce cash flow, which is a critical underpinning of these ratios. If this were to occur, it could be necessary to negotiate for an amendment to one or both of these financial covenants.

If low commodity prices continue for an extended period it could negatively affect our cash flows, which would reduce our liquidity.

As of December 31, 2014, the aggregate amount of our outstanding indebtedness was approximately $1.1 billion, however the company has continued to borrow under the credit facility since that time. As of December 31, 2014, our total debt comprised approximately 57% of our total capitalization and in 2014 we spent approximately 25% of our net cash provided by operating activities on interest payments. In addition, we may also incur additional indebtedness in the future. A high level of debt could adversely affect us in several ways, including the following:

- it may be more difficult for us to repay or make interest payments on our outstanding indebtedness;
- we estimate that we will use a significant portion of our 2015 cash flows to pay interest on our debt, which will reduce the amount of money we have for operations, capital expenditures, or other business activities;
- the amount of our interest expense could increase if we deem it necessary to borrow additional amounts; and
- our debt levels could limit our future business flexibility, including the necessity to sell assets at prices below market values.

Our level of indebtedness may adversely affect operations and raise issues related to maintaining certain properties.

While a portion of our leases are held by production, other leases require us to drill new wells in order to maintain the lease. Lower liquidity and other capital constraints may make it difficult to drill those wells prior to the lease expiration dates, which could result in our losing proved undeveloped reserves and production.

Our development 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. Although our 2014 total capital expenditures, including expenditures for leasehold acquisitions, drilling and infrastructure, were approximately $364 million, our 2015 capital expenditure budget has been reduced to between $110 to $125 million. Cash flow from operations is the principal source we intend to use for financing our future capital expenditures in 2015. Our cash flow from operations and access to capital are subject to a number of variables, including:

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

Cash flow from our operations and other capital resources may be insufficient to maintain planned levels of capital expenditures. If we are unable to fund our capital requirements, we may be required to curtail our operations even further, which in turn could lead to declines in our cash flows, or in our oil and natural gas reserves, or in a loss of properties.

For both 2014 and 2013, we have written down the carrying values on our oil and gas properties and could incur additional write-downs in the future.

The SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and natural gas properties for possible write-down or impairment (the "ceiling test"). Any capital costs in excess of the ceiling amount must be permanently written down. For the years ended December 31, 2014 and 2013, we reported non-cash write-downs on a before-tax basis of $445.4 million ($287.3 million after-tax) and $46.9 million ($30.0 million after tax), respectively, on our oil and gas properties. If oil and natural gas prices remain at their current low levels or decline further from the prices used in calculating the fourth quarter of 2014 ceiling test, we could be required to record additional non-cash write-downs of oil and gas properties as early as the first quarter of 2015, as the prices previously used in the ceiling test may be replaced by lower prices during 2015. Refer to Note 1 of the consolidated financial statements in this Form 10-K for further discussion of the ceiling test calculation.

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 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.

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.

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 credit facility or generate funds through property sales or joint ventures, neither of which can be assured. Even if we have the capital to drill new wells, 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 our 2014 estimates of proved reserves 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, 2014, approximately 66% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

Our Southeast Louisiana core area 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 6% of our 2014 reserves, 12% of our 2014 production and 23% of our 2014 revenues were located in our Southeast Louisiana core area. 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 Gustav and Ike in 2008, and by Hurricane Isaac in 2012. Since we do not 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 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. In addition, long-term restriction upon or freezing of the capital markets and legislation related to financial and banking reform may affect short-term or long-term liquidity.

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.

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. 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.

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.

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, state legislatures and various federal and state 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, 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.

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. 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 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.

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.
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.

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.

PART II

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

Common Stock, 2014 and 2013

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 2014 and 2013 were as follows:

	2014				2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$9.62	$10.26	$9.60	$2.63	$13.18	$11.81	$10.99	$11.59
High	$13.70	$13.01	$12.86	$9.21	$17.10	$15.63	$13.56	$14.90

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 of the consolidated financial statements in this Form 10-K, and we presently intend to continue a policy of using retained earnings for expansion of our business.

We had approximately 152 stockholders of record as of December 31, 2014.

Stock Repurchase Table

The following table summarizes repurchases of our common stock during the fourth quarter of 2014, 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)
October 1 - 31, 2014	4,300	$7.09	—	$---
November 1- 30, 2014	192	$6.81	—	—
December 1 - 31, 2014	18,461	$4.30	—	—
Total	22,953	$4.84	—	$---

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, 2014 is located in Note 6 of these consolidated financial statements in this Form 10-K.

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.
The graph below presents a comparison of the annual change in the cumulative total return on our common stock over the period from December 31, 2009 to December 31, 2014, with the cumulative total return of the Dow Jones U.S. Exploration & Production Index and the S&P 500 Index, over the same period. The graph assumes an investment of $100 (with reinvestment of all dividends) was invested on December 31, 2009, in our common stock at the closing market price at the beginning of this period and in each of the other indexes.

Item 6. Selected Financial Data (annual data in thousands except share & well amounts)	2014	2013	2012	2011	2010
Total Revenues from Continuing Operations (1)	$549,456	$584,401	$561,486	$597,809	$438,867
Income (Loss) from Continuing Operations, Before Income Taxes (1)	$(433,470)	$198	$37,773	$131,125	$72,225
Income (Loss) from Continuing Operations (1)	$(283,427)	$(2,442)	$21,701	$82,071	$45,146
Net Cash Provided by Operating Activities - Continuing Operations	$306,371	$311,447	$314,606	$373,058	$258,996
Per Share and Share Data					
Weighted Average Shares Outstanding	43,795	43,331	42,840	42,394	38,300
Earnings per Share--Basic(1)	$(6.47)	$(0.06)	$0.51	$1.94	$1.17
Earnings per Share--Diluted(1)	$(6.47)	$(0.06)	$0.50	$1.91	$1.16
Shares Outstanding at Year-End	43,918	43,402	42,930	42,485	41,999
Book Value per Share at Year-End	$18.09	$24.55	$24.52	$23.80	$21.36
Market Price					
High	$13.70	$17.10	$35.00	$47.32	$40.83
Low	$2.63	$10.99	$14.28	$21.81	$24.52
Year-End Close	$4.05	$13.50	$15.39	$29.72	$39.15
Assets					
Current Assets	$64,669	$92,489	$87,005	$334,594	$158,796
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$2,095,037	$2,588,817	$2,367,954	$1,892,866	$1,599,796
Total Assets	$2,173,347	$2,698,505	$2,473,463	$2,244,012	$1,771,305
Liabilities					
Current Liabilities	$148,919	$176,033	$179,412	$216,605	$157,102
Long-Term Debt	$1,074,534	$1,142,368	$916,934	$719,775	$471,624
Total Liabilities	$1,378,969	$1,633,155	$1,420,680	$1,232,661	$874,237
Stockholders' Equity	$794,378	$1,065,350	$1,052,783	$1,011,351	$897,068
Producing Wells					
Swift Operated	1,040	1,039	1,069	1,025	1,212
Outside Operated	25	25	50	46	119
Total Producing Wells	1,065	1,064	1,119	1,071	1,331
Wells Drilled (Gross)	36	48	71	44	56
Proved Reserves					
Natural Gas (Bcf)	686.7	815.1	597.6	616.8	423.0
Oil Reserves (MBoe)	49.7	53.0	43.3	30.9	39.3
NGL Reserves (MBoe)	29.7	30.4	49.2	25.8	23.0
Total Proved Reserves (MMBoe equivalent)	193.8	219.2	192.1	159.6	132.8

Production (MMBoe equivalent)	12.4	11.7	11.7	10.5	8.3
Average Sales Price (2)					
Natural Gas (per Mcf produced)	$3.88	$3.32	$2.42	$3.70	$3.96
Natural Gas Liquids (per barrel)	$31.83	$31.39	$35.07	$52.13	$42.44
Oil (per barrel)	$92.74	$103.42	$106.17	$107.00	$79.45
Boe Equivalent	$44.22	$50.11	$47.37	$57.22	$52.42

(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.

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, 2014, 2013 and 2012 included with this report. The following information contains forward-looking statements; see “Forward-Looking Statements” on page 34 of this report.

Overview

We are an independent oil and natural gas company formed in 1979 engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our South 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. Oil production accounted for 28% of our 2014 production and 59% of our oil and gas sales, and combined production of both oil and natural gas liquids (“NGLs”) constituted 43% of our 2014 production and 70% of our oil and gas sales. In 2014, we benefited from this production mix as oil prices were significantly higher than natural gas prices, on a Boe basis.

As a result of the July 2014 sale of a 36% interest in our Fasken area Eagle Ford shale properties to Saka Energi (as described below), we reduced the outstanding balance under our credit facility between June 30, 2014 and December 31, 2014 by over $100 million using a portion of the proceeds from the Saka Energi transaction.

- Recent crude oil price decline and its effect on our business: Crude oil prices are volatile and significant price movement can impact our cash flows, operating results and our future growth prospects. Oil prices started to decline in the second half of 2014, accelerating during the fourth quarter of 2014 through early 2015, falling from over $107 per barrel (as measured using the WTI crude oil price) in June 2014 to below $45 per barrel in January 2015, recovering slightly to approximately $51 per barrel as of February 25, 2015. Although the effect of this price decrease was somewhat muted on our 2014 results as it affected only a portion of our 2014 prices, we expect 2015 results will be affected in a more significant way as approximately 60% of the Company’s oil and gas sales revenue for 2014 was derived from crude oil sales.

- 2015 planned capital expenditures: We expect the current significantly lower oil and natural gas prices to reduce operating cash flows and have therefore meaningfully reduced our capital spending plans for 2015. The Company is targeting annual production levels of 11.4 to 11.6 MMBoe based on planned full-year capital expenditures of $110 to $125 million, with a focus on drilling activity in our dry gas Fasken area as well as in our South Texas oil, gas and condensate properties. A portion of our capital expenditure program is discretionary and may be further deferred, if necessary. We expect to fund 2015 capital expenditures primarily using cash flow from operations with the remaining balance supplied by borrowings under our credit facility or possibly proceeds from joint ventures or other arrangements.

- 2015 cost reduction initiatives: We are taking significant steps to reduce our future capital, operating and overhead costs. With the reduction in our capital spending plans for 2015, we terminated one of our two drilling contracts and are in discussions to reduce the day-rate for the remaining rig. We are also in negotiations with all of our primary suppliers and service companies to reduce our capital and operating cost structures. Through these initiatives, we anticipate achieving cost reductions of approximately 15-30% for a substantial portion of the goods and services consumed in our drilling and production operations. By focusing operations in our high quality Fasken and AWP areas we will continue to reduce our development costs by taking advantage of existing infrastructure and operating personnel. Additionally, we have proactively taken steps to materially reduce our overhead costs by (i) signing a new lease for less corporate office space at more attractive costs and (ii) carrying out a reduction-in-force that aligns with proposed spending levels in this lower commodity pricing environment.

- 2015 borrowing base redeterminations and credit facility financial covenants: Our credit facility provides for semi-annual borrowing base redeterminations by our lenders on or about May 1 and November 1 of each year. Due to the recent fall in oil prices, our borrowing base could be reduced at the next redetermination in May 2015. In addition, our bank credit agreement contains financial covenants detailing certain minimum financial ratios that must be maintained. The first is an adjusted working capital ratio of adjusted current assets to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0, which is below the Company's December 31, 2014 ratio of 1.9 to 1.0. There is also an interest coverage ratio, calculated on a trailing twelve month basis of EBITDAX to interest expense (as defined in the Credit Agreement), of no less than 2.75 to 1.0, which is below the Company's December 31, 2014 ratio of 4.9 to 1.0. Based upon our current projections of production and current commodity futures prices, we believe we will remain in compliance with these financial covenants throughout 2015; however, if oil prices were to decline further, we could find our operating earnings reduced to a level not in compliance with our interest coverage ratio by the end of 2015 or early 2016. Similarly, a significant reduction in our borrowing base

Table of Contents

during 2015 could lead to non-compliance with our adjusted working capital ratio. Either event could lead to a default under our credit facility, requiring us to seek a waiver, renegotiate our credit agreement or reduce or repay outstanding borrowings, which we anticipate being able to accomplish.

- 2015 liquidity: We expect to control our reduced liquidity during 2015 by scaling back our capital expenditures to match the current commodity pricing environment. Although we cannot predict nor control future commodity prices, we have already reduced our 2015 capital expenditure budget to accommodate market expectations of reduced commodity prices. As of December 31, 2014, we had approximately $220 million of remaining availability under our credit facility (excluding $1.6 million in letters of credit), which is subject to our borrowing base redetermination in May 2015. The Company has continued to borrow under the credit facility since December 31, 2014. We are simultaneously pursuing joint ventures and other arrangements which would enable us to support development of our core areas with additional third-party capital.

- Ability to capitalize on natural gas at current market prices: Natural gas prices declined during the second half of 2014 and into 2015, however selected natural gas properties can be economically developed at current market prices. Our Fasken properties in Webb County and part of our AWP properties in McMullen County can be economically developed today, while other areas may require a higher price environment to provide adequate economic returns. Our strategy includes a focus on natural gas and we plan to continue development on our prolific natural gas properties, along with development in economic liquids-rich areas if commodity prices improve.

2014 Operating Highlights

- Saka Energi transaction: On July 15, 2014, we closed a transaction with Saka Energi to fully develop 8,300 acres of natural gas Eagle Ford shale properties in our Fasken area. Saka Energi purchased a 36% full participating interest in the properties for $175 million in total cash consideration, with $125 million paid at closing and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date, January 1, 2014. As of December 31, 2014, approximately $29 million remained of Saka Energi's original $50 million carry obligation, which is expected to be fulfilled by the end of calendar year 2016 but is dependent on the pace of drilling in the Fasken area. At closing, Swift received proceeds of approximately $147 million, composed of the initial $125 million in cash consideration plus Saka Energi's share of capital costs, net of revenue between the January 1, 2014 effective date and the closing date. The proceeds from this transaction initially were used to pay down our credit facility and were partially offset by subsequent additional borrowings against the credit facility to fund development expenditures. This transaction allowed accelerated drilling and development of our Fasken properties in 2014.

- Enhancing Eagle Ford asset value through operating improvements 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. We are using proprietary 3D seismic techniques 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. Before completion operations commence, we conduct GEOFRAC logging of the horizontal well bore, which has led to more effective placement of frac stages and has also assisted in identifying sections of rock that are ideal for stimulation. These techniques have been effectively deployed in wells drilled in our Fasken and North AWP areas as well as the joint venture area in the central portion of AWP, proving the transferability of this technology. We have observed that longer laterals with additional frac stages and more intense treatment of each stage have resulted in improved rates of return of our Eagle Ford horizontal wells when comparing results using normalized oil and gas prices. Our current process allows us to drill wells in our Fasken area with laterals of over 7,500 feet and over 20 frac stages per well. We believe the successful extension of lateral lengths, increased number of frac stages and engineered spacing of these stages will result in further improvements in our economic returns across our acreage.

- Improved value of Eagle Ford shale assets through reductions 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 costs come down from those experienced in the prior year. For 2014, our average drilling cost per well has decreased to $3.4 million from $3.6 million during 2013, even though the average well included over 750 additional lateral feet in the current year. We have also experienced efficiency gains in our hydraulic fracturing activities, lowering the overall frac cost per stage while performing an average of four more frac stages per well and achieving better overall results as measured by rates of return and net present value. For 2014 compared to 2013, our average completion cost decreased approximately $20,000 per stage, while using additional proppant in each stimulated stage.

Table of Contents

- 2014 revenues and net income: Our 2014 revenues decreased 6% or $34.9 million, when compared to 2013, primarily due to the impact of lower oil prices and production volumes, partially offset by higher natural gas production volumes and pricing. Revenues decreased due to lower oil production in our Lake Washington field and lower overall production in our Artesia Wells field, partially offset by an increase in natural gas production volumes from our Fasken field and an increase in oil and natural gas production from our AWP field. Revenues also decreased from lower overall commodity pricing as oil prices were 10% lower in 2014, when compared to 2013, partially offset by a 17% increase in natural gas prices during the same period. Our net loss of $283.4 million for 2014 is primarily due to the $445.4 million non-cash write-down of our oil and gas properties.

- 2014 changes in reserve quantities and value: Our 12% or 25.4 MMBoe decrease in proved reserves quantities from 2013 to 2014, was principally due to the sale of a 36% interest in our Fasken Eagle Ford properties and production of 12.4 MMBoe during 2014, partially offset by various extensions, discoveries and revisions (mainly in our AWP Eagle Ford field). The 20% decrease in our PV-10 Value from 2013 and 2014 reflected not only these quantity decreases, but also the impact of lower oil and NGL prices during the last quarter of 2014.

- 2014 lease acquisition activity in Eagle Ford: The company recently acquired approximately 12,635 acres of high quality, contiguous Eagle Ford gas acreage at Oro Grande in La Salle County. The lease also contains a one year option to lease an additional contiguous 11,850 acres in McMullen County. This formation is 100% gas and we believe we can apply our enhanced techniques from our Fasken and AWP fields to this area in the Eagle Ford formation.

Liquidity and Capital Resources

- Outstanding bank borrowings: At December 31, 2014, we had $197.3 million in outstanding borrowings under our credit facility with a borrowing base and commitment amount of $417.6 million, after being automatically reduced from $450.0 million effective July 15, 2014, due to the Saka Energi transaction. The proceeds of approximately $147 million received at closing were immediately used to pay down our outstanding borrowings under the credit facility, with subsequent borrowings against the credit facility during the second half of the year to fund development activities.

- 2014 capital expenditures: Our capital expenditures on a cash flow basis were $386.3 million in 2014, compared to $540.4 million for 2013. The expenditures were devoted to drilling and completion activity in our South Texas core region as we drilled 20 wells in our AWP Eagle Ford field and 16 wells in our Fasken field during the year. These expenditures were funded by $306.4 million of cash provided by operating activities along with borrowings under our credit facility.

- Net cash provided by operating activities: For 2014, our net cash provided by operating activities was $306.4 million, representing a $5.1 million or 2% decrease, compared to $311.4 million generated during 2013, primarily due to the impacts of lower oil prices and production, partially offset by higher natural gas production and prices.

Table of Contents

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2014 were as follows (in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Non-cancelable operating leases (1)	$12,560	$79	$—	$—	$—	$—	$12,639
Asset retirement obligation (2)	10,709	3,040	2,877	2,618	568	53,019	72,831
Drilling, Completion and Geoscience Contracts	13,109	—	—	—	—	—	13,109
Gas transportation and Processing (3)	12,663	12,543	10,057	10,239	8,720	7,397	61,619
7-1/8% senior notes due 2017	—	—	250,000	—	—	—	250,000
8-7/8% senior notes due 2020	—	—	—	—	—	225,000	225,000
7-7/8% senior notes due 2022	—	—	—	—	—	400,000	400,000
Interest Cost	69,281	69,281	60,375	51,469	51,469	88,734	390,609
Credit facility (4)	—	—	197,300	—	—	—	197,300
Total	$118,322	$84,943	$520,609	$64,326	$60,757	$774,150	$1,623,107

(1) Subsequent to December 31, 2014, we signed a new lease commencing on March 1, 2015. For additional discussion regarding the terms and obligations of this lease refer to Note 5 of the consolidated financial statements in this Form 10-K.
(2) Amounts shown by year are the net present value at December 31, 2014.
(3) Amounts shown represent fees for the minimum delivery obligations. Any amount of transportation utilized in excess of the minimum will reduce future year obligations.
(4) The credit facility expires in November 2017 and these amounts exclude $1.6 million standby letters of credit outstanding under this facility.

As of December 31, 2014, we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Proved Oil and Gas Reserves

We have added proved reserves over the past three years primarily through our drilling activities, including 18.2 MMBoe added in 2014, 76.3 MMBoe added in 2013, and 43.8 MMBoe added in 2012. The 2014 proved reserves additions from drilling activities consisted primarily of additions in the AWP Eagle Ford field in South Texas based on the results of the horizontal drilling program conducted in the area during the year. We obtained reasonable certainty regarding these reserves additions by applying the same methodologies that have been used historically in this area. We also sold approximately 30.9 MMBoe of reserves during 2014 in conjunction with our Fasken disposition, as noted in Note 8 of our consolidated financial statements in this Form 10-K. At year-end 2014, 34% of our total proved reserves were proved developed, compared with 29% at year-end 2013 and 34% at year-end 2012.

At December 31, 2014, our proved reserves were 193.8 MMBoe with a PV-10 Value of $1.9 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), a decrease in the PV-10 Value of approximately $481 million, or 20%, from the prior year-end levels. In 2014, our proved natural gas reserves decreased 128.4 Bcf, or 16%, while our proved oil reserves decreased 3.3 MMBbl, or 6%, and our NGL reserves decreased 0.7 MMBbl, or 2%, for a total equivalent decrease of 25.4 MMBoe, or 12%.

We use the preceding 12-months' average price based on closing prices on the first business day of each month, adjusted for price differentials, in calculating our average prices used in the PV-10 Value calculation. Our average natural gas price used in the PV-10 Value calculation for 2014 was $4.32 per Mcf. This average price increased from the average price of $3.41 per Mcf used in the PV-10 calculation for 2013. Our average oil price used in the PV-10 Value calculation for 2014 was $93.64 per Bbl. This average price decreased from the average price of $104.38 per Bbl used in the PV-10 calculation for 2013.

Results of Operations

Revenues — Years Ended December 31, 2014, 2013 and 2012

2014 - Our revenues in 2014 decreased by 6% compared to revenues in 2013, due to the impact of lower oil prices and production volumes, partially offset by higher natural gas production volumes and pricing. Average oil prices we received were 10% lower than those received during 2013, while natural gas prices were 17% higher, and NGL prices were 1% higher.

Table of Contents

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.

Crude oil production was 28%, 33% and 32% of our production volumes while crude oil sales were 59%, 69% and 72% of oil and gas sales for the years ended December 31, 2014, 2013 and 2012, respectively. Natural gas production was 57%, 47% and 52% of our production volumes while natural gas sales were 30%, 19% and 16% of oil and gas sales for the years ended December 31, 2014, 2013 and 2012, 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, 2014, 2013 and 2012:

Core Areas	Oil and Gas Sales (In Millions)			Net Oil and Gas Production Volumes (MBoe)		
	2014	2013	2012	2014	2013	2012
Southeast Louisiana	$124.2	$168.0	$215.0	1,459	1,797	2,227
South Texas (1)	382.4	360.2	290.1	10,239	9,009	8,555
Central Louisiana	39.5	54.9	52.6	656	897	898
Other	1.7	2.1	0.7	33	43	20
Total	$547.8	$585.2	$558.4	12,387	11,746	11,700

(1) Our 2014 South Texas oil and gas sales include $62.2 million for Artesia Wells, $224.8 million for AWP, $87.2 million for Fasken and $8.2 million for other South Texas fields. Our 2014 South Texas net oil and gas production volumes include 1,786 million MBoe for Artesia Wells, 4,636 million MBoe for AWP, 3,565 million MBoe for Fasken and 252 million MBoe for other South Texas fields.

Our production increase from 2013 to 2014 was primarily due to an increase of natural gas production from increased drilling in our Fasken field, plus an increase in oil and natural gas production at our AWP field. These increases were partially offset by a decrease in overall production for our Artesia Wells field and a decrease in oil production in our Lake Washington field.

In 2014, our $37.4 million, or 6% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $9.7 million unfavorable impact on sales, with a decrease of $35.4 million due to the 10% decrease in oil prices received, partially offset by an increase of $24.9 million attributable to the 18% increase in natural gas prices and an increase of $0.8 million due to the 1% increase in NGL prices.
- Volume variances that had a $27.7 million unfavorable impact on sales, with a $42.7 million decrease attributable to the 0.4 million Bbl decrease in oil production volumes and a $15.9 million decrease due to the 0.5 million Bbl decrease in NGL production volumes, partially offset by a $30.9 million increase due to the 9.4 Bcf increase in natural gas production volumes.

In 2013, our $26.8 million, or 5% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that accounted for approximately $10 million of the favorable increase as gas prices were up 37%, partially offset by lower prices for oil (down 3%) and NGLS (down 10%); and
- Volume variances that had an approximate $17 million favorable impact on sales attributable to higher oil and NGL production, partially offset by a reduction in natural gas volumes.

30

Table of Contents

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, by quarter, for the years ended December 31, 2014, 2013 and 2012:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2012							
First Quarter	884	376	9.2	2,799	$111.99	$45.30	$2.18
Second Quarter	905	430	9.5	2,918	$108.02	$35.25	$2.01
Third Quarter	870	512	9.0	2,875	$102.73	$31.29	$2.52
Fourth Quarter	1,115	544	8.7	3,108	$102.73	$31.42	$3.04
Total	3,774	1,862	36.4	11,700	$106.17	$35.07	$2.42
2013							
First Quarter	988	557	7.6	2,819	$108.45	$29.90	$2.96
Second Quarter	911	549	7.9	2,778	$103.15	$29.74	$3.86
Third Quarter	1,004	600	8.7	3,057	$108.17	$31.67	$3.15
Fourth Quarter	1,023	615	8.7	3,092	$94.14	$33.93	$3.32
Total	3,926	2,320	32.9	11,746	$103.42	$31.39	$3.32
2014							
First Quarter	931	478	9.2	2,944	$99.38	$36.27	$4.20
Second Quarter	890	434	12.7	3,449	$101.67	$33.93	$4.16
Third Quarter	870	482	9.9	2,994	$96.12	$33.39	$3.55
Fourth Quarter	820	418	10.6	3,000	$71.94	$22.74	$3.58
Total	3,511	1,812	42.4	12,387	$92.74	$31.83	$3.88

For the years ended December 31, 2014, 2013 and 2012, we recorded net gains (losses) of $1.3 million, ($0.9) million and $2.3 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $92.52, $102.93 and $106.77 for the years ended December 31, 2014, 2013 and 2012, respectively, and our average natural gas price would have been $3.93, $3.35 and $2.42 for the years ended December 31, 2014, 2013 and 2012, respectively.

Costs and Expenses

2014 - Our expenses for the year ended December 31, 2014 increased $398.7 million, or 68%, compared to the prior year levels, for the reasons noted below. Our expenses in 2014 increased $0.3 million when compared to those in 2013 (excluding the 2014 and 2013 ceiling test write-downs). During 2014, we saw some tightening in the availability of services and supplies including some upward pressure on service costs, but we believe that these costs will decrease from current levels with the recent decline in oil prices.

Lease Operating Cost. These expenses decreased $6.5 million, or 7%, compared to the level of such expenses for the year ended December 31, 2013, primarily due to lower salt water disposal, labor and maintenance costs, partially offset by higher utilities costs. Our lease operating costs per Boe produced were $7.52 and $8.49 for the years ended December 31, 2014 and 2013, respectively.

Transportation and gas processing. These expenses were comparable to the level of such expenses for the year ended December 31, 2013. Our transportation and gas processing costs per Boe produced were $1.71 and $1.79 for the years ended December 31, 2014 and 2013, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $14.8 million, or 6%, from those during the year ended December 31, 2013, due to increased production and a higher depletable base. Our DD&A rate per Boe of production was $21.60 and $21.52 for the years ended December 31, 2014 and 2013, respectively.

General and Administrative Expenses, Net. These expenses decreased $5.8 million or 13%, compared to the level of such expenses for the year ended December 31, 2013, due to lower stock compensation, a lower benefit accrual and lower salaries, partially offset by higher legal fees and lower capitalized costs. For the years ended December 31, 2014 and 2013, our capitalized general and administrative costs totaled $26.3 million and $31.8 million, respectively. Our net general and administrative expenses per Boe produced were $3.20 and $3.87 for the years ended December 31, 2014 and 2013, respectively. The supervision fees recorded as a reduction to general and administrative expenses were $12.7 million and $11.6 million for the years ended December 31, 2014 and 2013, respectively.

Severance and Other Taxes. These expenses decreased $5.7 million, or 13%, from the year ended December 31, 2013. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.8% and 7.3% for the years ended December 31, 2014 and 2013, respectively. The change in rate was primarily driven by higher production in South Texas which carries a lower severance tax rate than in Louisiana.

Interest. Our gross interest cost for the year ended December 31, 2014 was $78.2 million, of which $5.0 million was capitalized. Our gross interest cost for the year ended December 31, 2013 was $76.6 million, of which $7.2 million was capitalized. The increase in interest came from increased credit facility borrowings during 2014.

Write-down of oil and gas properties. Due to the effects of pricing, timing of projects and changes in our reserves product mix, in 2014 and 2013 we reported non-cash write-downs on a before-tax basis of $445.4 million ($287.3 million after tax) and $46.9 million ($30.0 million after tax), respectively, for our oil and natural gas properties.

Income Taxes. Our effective income tax rate was 34.6% for the year ended December 31, 2014. For the year ended December 31, 2013 the rate was over 100% due to the proportional effect of non-deductible expenses compared to pre-tax book income that was close to break-even.

2013 - Our expenses for the year ended December 31, 2013 increased $60.5 million, or 12%, compared to the prior year levels, for the reasons noted below.

Lease Operating Cost. These expenses increased $1.9 million, or 2%, compared to the level of such expenses for the year ended December 31, 2012, due to higher costs in our South Texas region for chemical treating, compressor rentals and lease operator costs, partially offset by lower salt water disposal costs in South Texas. Our lease operating costs per Boe produced were $8.49 and $8.36 for the years ended December 31, 2013 and 2012, respectively.

Transportation and gas processing. These expenses increased $1.6 million, or 8%, compared to the level of such expenses for the year ended December 31, 2012, due to additional NGL production. Our transportation and gas processing costs per Boe produced were $1.79 and $1.66 for the years ended December 31, 2013 and 2012, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $3.4 million, or 1%, from those during the year ended December 31, 2012, due to a higher depletable base including higher future development costs, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $21.52 and $21.31 for the years ended December 31, 2013 and 2012, respectively.

General and Administrative Expenses, Net. These expenses decreased $1.7 million or 4%, compared to the level of such expenses for the year ended December 31, 2012, due to lower stock compensation, partially offset by higher salaries and burdens and higher temporary labor costs. For the years ended December 31, 2013 and 2012, our capitalized general and administrative costs totaled $31.8 million and $31.1 million, respectively. Our net general and administrative expenses per Boe produced were $3.87 and $4.03 for the years ended December 31, 2013 and 2012, respectively. The supervision fees recorded as a reduction to general and administrative expenses were $11.6 million and $11.3 million for the years ended December 31, 2013 and 2012, respectively.

Severance and Other Taxes. These expenses decreased $4.8 million, or 10%, from the year ended December 31, 2012. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.3% and 8.5% for the years ended December 31, 2013 and 2012, respectively. The change in rate was primarily driven by higher oil production in

South Texas as our Texas oil production carries a lower severance tax rate than in Louisiana.

Interest. Our gross interest cost for the year ended December 31, 2013 was $76.6 million, of which $7.2 million was capitalized. Our gross interest cost for the year ended December 31, 2012 was $65.2 million, of which $7.9 million was capitalized. The increase in interest came from increased credit facility borrowings during 2013.

Write-down of oil and gas properties. Due to the effects of pricing, timing of projects and changes in our reserves product mix, in 2013 we reported a non-cash write-down on a before-tax basis of $46.9 million ($30.0 million after tax) for our oil and natural gas properties.

Table of Contents

Income Taxes. Our effective income tax rate was over 100% for the year ended December 31, 2013. As our net income was near break-even tax expense is primarily attributable to non-deductible book expenses. For the year ended December 31, 2012 our effective rate was 42.5%.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized. We compute the provision for depreciation, depletion, and amortization (“DD&A”) of oil and natural gas properties using the unit-of-production method.

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

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months’ average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

Due to the effects of pricing, timing of projects and changes in our reserves product mix, in 2014 and 2013 we reported non-cash write-downs on a before-tax basis of $445.4 million ($287.3 million after tax) and $46.9 million ($30.0 million after tax), respectively, on our oil and natural gas properties.

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

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

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09 which provides a single, comprehensive revenue recognition model for all contracts with customers across various industries. The guidance is effective for annual and interim reporting periods beginning after December 15, 2016. We are currently reviewing the new requirements to determine the impact of this guidance on our financial statements.

Table of Contents

Forward-Looking Statements

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

Forward-looking statements may include statements about our:

• oil and natural gas pricing expectations;
• business strategy;
• estimated oil and natural gas reserves or the present value thereof;
• technology;
• our borrowing capacity, cash flows and liquidity;
• financial strategy, budget, projections and operating results;
• asset disposition efforts or the timing or outcome thereof;
• prospective joint ventures, their structure and substance, and the likelihood of their finalization or the timing thereof;
• the amount, nature and timing of capital expenditures, including future development costs;
• timing and amount of future production of oil and natural gas;
• availability of drilling and production equipment or availability of oil field labor;
• availability and terms of capital;
• drilling of wells;
• marketing and transportation of oil and natural gas;
• costs of exploiting and developing our properties and conducting other operations;
• competition in the oil and natural gas industry;
• general economic conditions;
• opportunities to monetize assets;
• effectiveness of our risk management activities;
• environmental liabilities;
• counterparty credit risk;
• governmental regulation and taxation of the oil and natural gas industry;
• developments in world oil markets and in oil and natural gas-producing countries;
• uncertainty regarding our future operating results;
• plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2014. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

Table of Contents

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. This commodity pricing volatility has continued with unpredictable price swings throughout 2013 and 2014.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. For additional discussion related to our price-risk management policy, refer to Note 1 of the consolidated financial statements in this Form 10-K.

Income Tax Carryforwards. As of December 31, 2014, the Company has net deferred tax carryforward assets of $132.3 million for federal net operating losses, $2.1 million for federal alternative minimum tax credits and $4.7 million, net of a $10.9 million valuation allowance, for deferred state tax net operating loss carryforwards which in management's judgment will more likely than not be utilized to offset future taxable earnings. Changes in markets conditions or significant changes in the Company's ownership could impact our ability to utilize these carryforwards.

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

Concentration of Sales Risk. Over the last several years, a large portion of our oil and gas sales have been to Shell Oil Corporation and affiliates and we expect to continue this relationship in the future. For the years ended December 31, 2014, 2013 and 2012, Shell Oil Company and affiliates accounted for 21%, 33% and 46% of our total oil and gas gross receipts, respectively. We believe that the risk of these unsecured receivables is mitigated by the short-term sales agreements we have in place as well as the size, reputation and nature of their business.

Interest Rate Risk. Our senior notes due in 2017, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2014, we had $197.3 million drawn under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank’s base rate would constitute 33 basis points and would not have a material adverse effect on our future cash flows.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Table of Contents

Management's Report on Internal Control Over Financial Reporting

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

Management of the Company assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria) (2013 framework) in Internal Control-Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2014.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance of achieving their control objectives. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2014, based on their audit. The Public Company Accounting Oversight Board (United States) standards require that they plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Their audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as they considered necessary in the circumstances.

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited Swift Energy Company and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Swift Energy Company and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Swift Energy Company and subsidiaries' maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Swift Energy Company and subsidiaries' as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014 and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 2, 2015

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries (the “Company”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Swift Energy Company and subsidiaries' internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 2, 2015 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 2, 2015

Table of Contents

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

	December 31, 2014	December 31, 2013
ASSETS		
Current Assets:		
Cash and cash equivalents	$406	$3,277
Accounts receivable	48,451	70,897
Deferred tax assets	6,243	10,715
Other current assets	9,569	7,600
Total Current Assets	64,669	92,489
Property and Equipment:		
Property and Equipment, including $64,903 and $71,452 of unproved property costs not being amortized, respectively	5,934,155	5,714,099
Less – Accumulated depreciation, depletion, and amortization	(3,839,118)	(3,125,282)
Property and Equipment, Net	2,095,037	2,588,817
Other Long-Term Assets	13,641	17,199
Total Assets	$2,173,347	$2,698,505
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$68,244	$82,318
Accrued capital costs	41,461	61,164
Accrued interest	21,389	21,561
Undistributed oil and gas revenues	17,825	10,990
Total Current Liabilities	148,919	176,033
Long-Term Debt	1,074,534	1,142,368
Deferred Tax Liabilities	86,376	241,205
Asset Retirement Obligations	62,122	63,225
Other Long-Term Liabilities	7,018	10,324
Commitments and Contingencies	—	—
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 150,000,000 shares authorized, 44,379,463 and 43,915,346 shares issued, and 43,918,029 and 43,401,920 shares outstanding, respectively	444	439
Additional paid-in capital	771,972	762,242
Treasury stock held, at cost, 461,434 and 513,426 shares, respectively	(9,855)	(12,575)
Retained earnings	31,817	315,244
Total Stockholders' Equity	794,378	1,065,350
Total Liabilities and Stockholders' Equity	$2,173,347	$2,698,505

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

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

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Oil and gas sales	$547,790	$585,229	$558,390
Price-risk management and other, net	1,666	(828)	3,096
Total Revenues	549,456	584,401	561,486
Costs and Expenses:			
General and administrative, net	39,629	45,423	47,097
Depreciation, depletion, and amortization	267,590	252,769	249,344
Accretion of asset retirement obligation	5,712	6,181	5,121
Lease operating cost	93,214	99,731	97,835
Transportation and gas processing	21,140	21,044	19,467
Severance and other taxes	37,038	42,725	47,546
Interest expense, net	73,207	69,382	57,303
Write-down of oil and gas properties	445,396	46,948	—
Total Costs and Expenses	982,926	584,203	523,713
Income (Loss) Before Income Taxes	(433,470)	198	37,773
Provision (Benefit) for Income Taxes	(150,043)	2,640	16,072
Net Income (Loss)	$(283,427)	$(2,442)	$21,701
Per Share Amounts-			
Basic: Net Income (Loss)	$(6.47)	$(0.06)	$0.51
Diluted: Net Income (Loss)	$(6.47)	$(0.06)	$0.50
Weighted Average Shares Outstanding - Basic	43,795	43,331	42,840
Weighted Average Shares Outstanding - Diluted	43,795	43,331	43,174

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

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

	Year Ended December 31, 2014	2013	2012
Net Income (Loss):	$(283,427)	$(2,442)	$21,701
Other Comprehensive Income:			
Unrealized gains (losses) related to price risk management transactions, before taxes	—	—	1,210
Provision (benefit) for income taxes	—	—	440
Unrealized gains (losses) related to price risk management transactions, net of taxes	—	—	770
Less: reclassification of (gains) losses on price risk management transactions to net income, before taxes	—	—	(1,210)
(Provision) benefit for income taxes	—	—	(440)
Reclassification of (gains) losses on price risk management transactions to net income, net of taxes	—	—	(770)
Comprehensive Income (Loss)	$(283,427)	$(2,442)	$21,701

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total
Balance, December 31, 2011	$430	$727,286	$(12,350)	$295,985	$1,011,351
Stock issued for benefit plans (50,987 shares)	—	354	1,300	—	1,654
Shares issued from option exercises (63,040 shares)	1	635	—	—	636
Purchase of treasury shares (86,812 shares)	—	—	(2,805)	—	(2,805)
Tax benefits from share-based compensation	—	175	—	—	175
Employee stock purchase plan (42,624 shares)	—	1,076	—	—	1,076
Issuance of restricted stock (375,157 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	18,995	—	—	18,995
Net Income	—	—	—	21,701	21,701
Balance, December 31, 2012	$435	$748,517	$(13,855)	$317,686	$1,052,783
Stock issued for benefit plans (104,890 shares)	—	(1,171)	2,793	—	1,622
Shares issued from option exercises (1,125 shares)	—	4	—	—	4
Purchase of treasury shares (98,020 shares)	—	—	(1,513)	—	(1,513)
Tax benefits from share-based compensation	—	(1,607)	—	—	(1,607)
Employee stock purchase plan (72,273 shares)	1	945	—	—	946
Issuance of restricted stock (391,581 shares)	3	(3)	—	—	—
Amortization of share-based compensation	—	15,557	—	—	15,557
Net Loss	—	—	—	(2,442)	(2,442)
Balance, December 31, 2013	$439	$762,242	$(12,575)	$315,244	$1,065,350
Stock issued for benefit plans (154,665 shares)	—	(1,876)	3,785	—	1,909
Purchase of treasury shares (102,673 shares)	—	—	(1,065)	—	(1,065)
Employee stock purchase plan (71,825 shares)	1	823	—	—	824
Issuance of restricted stock (392,292 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	10,787	—	—	10,787
Net Loss	—	—	—	(283,427)	(283,427)
Balance, December 31, 2014	$444	$771,972	$(9,855)	$31,817	$794,378

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

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

	Year Ended December 31, 2014	2013	2012
Cash Flows from Operating Activities:			
Net income (loss)	$(283,427)	$(2,442)	$21,701
Adjustments to reconcile net income to net cash provided by operating activities-			
Write-down of oil and gas properties	445,396	46,948	—
Depreciation, depletion, and amortization	267,590	252,769	249,344
Accretion of asset retirement obligation	5,712	6,181	5,121
Deferred income taxes	(150,357)	2,647	17,231
Share-based compensation expense	7,309	10,099	13,795
Other	(8,910)	(5,443)	976
Change in assets and liabilities-			
(Increase) decrease in accounts receivable and other current assets	21,411	(1,894)	(1,534)
Increase (decrease) in accounts payable and accrued liabilities	1,505	2,607	(1,013)
Increase (decrease) in income taxes payable	314	(224)	82
Increase (decrease) in accrued interest	(172)	199	8,903
Net Cash Provided by Operating Activities	306,371	311,447	314,606
Cash Flows from Investing Activities:			
Additions to property and equipment	(386,336)	(540,368)	(757,755)
Proceeds from the sale of property and equipment	145,035	6,991	528
Funds withdrawn from restricted cash account	25,994	—	—
Funds deposited into restricted cash account	(25,994)	—	—
Net Cash Used in Investing Activities	(241,301)	(533,377)	(757,227)
Cash Flows from Financing Activities:			
Proceeds from long-term debt issuances	—	—	157,500
Proceeds from bank borrowings	487,400	622,500	371,300
Payments of bank borrowings	(555,100)	(396,900)	(331,900)
Net proceeds from issuances of common stock	824	950	1,712
Purchase of treasury shares	(1,065)	(1,513)	(2,805)
Payments of debt issuance costs	—	—	(4,712)
Net Cash Provided by (Used in) Financing Activities	(67,941)	225,037	191,095
Net Increase (Decrease) in Cash and Cash Equivalents	(2,871)	3,107	(251,526)
Cash and Cash Equivalents at Beginning of Period	3,277	170	251,696
Cash and Cash Equivalents at End of Period	$406	$3,277	$170
Supplemental Disclosures of Cash Flows Information:			
Cash paid during period for interest, net of amounts capitalized	$70,933	$67,070	$46,911
Cash paid during period for income taxes	$150	$217	$248

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

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

Subsequent Events. We have evaluated subsequent events of our consolidated financial statements. In January of 2015 the company entered into a new lease agreement for office space in Houston, Texas. For additional discussion regarding the term and obligations of this lease refer to Note 5 of these consolidated financial statements. There were no other material subsequent events requiring additional disclosure in these financial statements.

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

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

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

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated.

Property and Equipment. We follow the “full-cost” method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years ended December 31, 2014, 2013 and 2012, such internal costs capitalized totaled $26.3 million, $31.8 million and $31.1 million,

Table of Contents

respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 4 of these consolidated financial statements for further discussion on capitalized interest costs).

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

(in thousands)	December 31, 2014	December 31, 2013
Property and Equipment		
Proved oil and gas properties	$5,826,995	$5,600,279
Unproved oil and gas properties	64,903	71,452
Furniture, fixtures, and other equipment	42,257	42,368
Less – Accumulated depreciation, depletion, and amortization	(3,839,118)	(3,125,282)
Property and Equipment, Net	$2,095,037	$2,588,817

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

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

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

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

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis.

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

Due to the effects of pricing, timing of projects and changes in our reserves product mix, in 2014 and 2013 we reported non-cash write-downs on a before-tax basis of $445.4 million and $46.9 million, respectively, on our oil and natural gas properties.

If future capital expenditures out pace future discounted net cash flows in our reserve calculations, 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) or if oil or natural gas prices decline, non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets. Natural gas balancing receivables are reported in “Other current assets” on the accompanying consolidated balance sheets when our ownership share of production exceeds sales. As of December 31, 2014 and 2013, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2014 and 2013, we had an allowance for doubtful accounts of approximately $0.1 million, respectively. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balance on the accompanying consolidated balance sheets.

At December 31, 2014, our “Accounts receivable” balance included $34.8 million for oil and gas sales, $8.4 million for joint interest owners, $3.1 million for severance tax credit receivables and $2.2 million for other receivables. At December 31, 2013, our “Accounts receivable” balance included $56.9 million for oil and gas sales, $1.6 million for joint interest owners, $11.6 million for severance tax credit receivables and $0.8 million for other receivables.

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

The 7.125% senior notes due in 2017 mature on June 1, 2017, and the remaining balance of their issuance costs at December 31, 2014, was $1.3 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the remaining balance of their issuance costs at December 31, 2014, was $3.1 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their remaining issuance costs at December 31, 2014, was $5.9 million. The remaining balance of revolving credit facility issuance costs at December 31, 2014, was $2.3 million.

Price-Risk Management Activities. The Company follows FASB ASC 815-10, which requires that changes in the derivative’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the consolidated balance sheets as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

Table of Contents

Prior to January 1, 2013, the Company had elected hedge accounting on all qualifying derivative instruments. As of December 31, 2012, the Company did not have any outstanding derivatives. For all derivatives entered into after January 1, 2013, the Company elected not to apply hedge accounting. The changes in the fair value of our derivatives initiated after January 1, 2013 are recognized in "Price-risk management and other, net” on the accompanying consolidated statements of operations.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price floors, calls, swaps, collars and participating collars. Prior to January 1, 2013, all hedges were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that was highly effective and was designated, documented and qualified as a cash flow hedge, to the extent that the hedge was effective, were recorded in “Accumulated other comprehensive income, net of income tax” on the balance sheet. When the hedged transactions were recorded upon the actual sale of the oil and natural gas, those gains or losses were reclassified from “Accumulated other comprehensive income, net of income tax” and were recorded in “Price-risk management and other, net” on the accompanying consolidated statements of operations. Changes in the fair value of derivatives that did not meet the criteria for hedge accounting, and the ineffective portion of the hedge for which hedge accounting was elected, were recognized in "Price-risk management and other, net."

For the years ended December 31, 2014, 2013 and 2012, we recognized net gains (losses) of $1.3 million, ($0.9) million and $2.3 million, respectively, relating to our derivative activities. The ineffectiveness for the year ended December 31, 2012, was not material. The effects of our derivatives are included in the "Other" section of our Cash Flows from Operating Activities on the accompanying consolidated statements of cash flows.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. The fair value of our unsettled derivative assets at December 31, 2014 was $2.5 million which was recognized on the accompanying consolidated balance sheet in “Other current assets.” The fair value of our unsettled derivative liabilities at December 31, 2014 was $0.1 million which was recognized on the accompanying consolidated balance sheet in “Accounts payable and accrued liabilities.”

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for all derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. If all counterparties were in a default situation, the Company, under the right of set-off, would show a net derivative fair value asset of $2.4 million at December 31, 2014. For further discussion related to the fair value of the Company's derivatives, refer to Note 9 of these consolidated financial statements.

At December 31, 2014, we had $1.0 million in receivables for settled derivatives which were recognized on the accompanying balance sheet in “Accounts receivable” and were subsequently collected in January of 2015.

The following tables summarize the weighted average prices and future production volumes for our unsettled derivative contracts in place as of December 31, 2014.

Natural Gas Derivatives (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Swap Fixed Price	Collars Floor Price	Ceiling Price
2015 Contracts				
Swaps	600,000	$ 4.42		

Collars	1,280,000	$4.05	$4.88

Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Swap Fixed Price
2015 Contracts		
Swaps	7,280,000	$(0.02)

48

Table of Contents

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to “General and administrative, net”, on the accompanying consolidated statements of operations. Our supervision fees are based on COPAS industry guidelines. The amount of supervision fees charged for the years ended December 31, 2014, 2013 and 2012, respectively, did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $12.7 million, $11.6 million and $11.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Other Current Assets. Included in "Other current assets" on the accompanying consolidated balance sheets are inventories which consist primarily of tubulars and other equipment and supplies that we expect to place in service in production operations. Our inventories are recorded at cost (weighted average method) and totaled $3.1 million and $3.5 million at December 31, 2014 and 2013, respectively.

Included in "Other current assets" on the accompanying consolidated balance sheets are prepaid expenses totaling $3.9 million and $3.3 million at December 31, 2014 and 2013. These prepaid amounts cover well insurance, drilling contracts and various other prepaid expenses.

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

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense.

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

	December 31, 2014	December 31, 2013
Trade accounts payable (1)	$31,153	$30,769
Accrued operating expenses	10,784	16,016
Accrued payroll costs	8,100	10,938
Asset retirement obligations – current portion	10,709	15,859
Accrued taxes	2,957	5,845
Other payables	4,541	2,891
Total accounts payable and accrued liabilities	$68,244	$82,318

(1) Included in “trade accounts payable” are liabilities of approximately $13.7 million and $26.1 million at December 31, 2014 and 2013, respectively, for outstanding checks.

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

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners' receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. From certain customers we also obtain letters of credit or parent company guarantees, if applicable, to reduce risk of loss. For the years ended December 31, 2014, 2013 and 2012, Shell Oil Company and affiliates accounted for 21%, 33% and 46% of our total oil and gas gross receipts, respectively. Kinder Morgan and Plains Marketing accounted for approximately 20% and 11% of our total oil and gas gross receipts in 2014, 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.

Table of Contents

Short-Term Restricted Cash (Saka Energi Transaction). On July 15, 2014, we closed our transaction with PT Saka Energi Indonesia ("Saka Energi") to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi.

Subject to the terms of the transaction, Swift Energy and Saka Energi were depositing cash on a monthly basis into a separate Swift Energy-owned bank account to fund their respective portions of the on-going Fasken development program for the following month. All cash deposited in the account was contractually restricted for use in the Fasken development program and therefore was recorded as restricted cash until the Company performed the related development activities. During the fourth quarter of 2014 this cash requirement process was discontinued and all unused amounts were refunded.

During the year Saka Energi deposited $29.8 million into the account, from which $7.1 million was withdrawn from the account in order to fund on-going development operations in the Fasken area, while the remainder was refunded to Saka upon discontinuance of the cash requirement process noted above. The cash changes from the account relating to Saka Energi’s contributions are shown in the operating activities section of the accompanying consolidated statements of cash flows. The cash changes from the account relating to Swift Energy’s contributions are reported in the investing activities section on the accompanying consolidated statements of cash flows.

Long-Term Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy plugging and abandonment obligations. As of December 31, 2014 and 2013, these assets were approximately $1.0 million. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields. Restricted cash balances are reported in “Other Long-Term Assets” on the accompanying consolidated balance sheets.

Asset Retirement Obligations. We record these obligations in accordance with the guidance contained in FASB ASC 410-20. This guidance requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the “Property and Equipment” balance on our accompanying consolidated balance sheets. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

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

Asset Retirement Obligations as of December 31, 2012	$86,777
Accretion expense	6,181
Liabilities incurred for new wells and facilities construction	1,588
Reductions due to sold and abandoned wells and facilities	(16,394)
Revisions in estimates	932
Asset Retirement Obligations as of December 31, 2013	$79,084
Accretion expense	5,712
Liabilities incurred for new wells and facilities construction	469
Reductions due to sold and abandoned wells and facilities	(8,253)
Revisions in estimates	(4,181)
Asset Retirement Obligations as of December 31, 2014	$72,831

At December 31, 2014 and 2013, approximately $10.7 million and $15.9 million, respectively, of our asset retirement obligation was classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying consolidated balance sheets.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance. The guidance is effective for annual and interim reporting periods beginning after December 15, 2016 and upon adoption, entities are required to recognize revenue using the following five-step model: identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract, and recognize revenue as the entity satisfies each performance obligation. Adoption of this standard could result in retrospective application,

Table of Contents

either in the form of recasting all prior periods presented or a cumulative adjustment to equity in the period of adoption. We are currently reviewing the new requirements to determine the impact of this guidance on our financial statements.

2. Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Basic earnings per share (“Basic EPS”) has been computed using the weighted average number of common shares outstanding during each period. Diluted earnings per share ("Diluted EPS") assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. As we recognized a net loss for the years ended December 31, 2014 and 2013, the unvested share-based payments and stock options were not recognized in diluted earnings per share (“Diluted EPS”) calculations as they would be antidilutive. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the year ended December 31, 2012, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2014, 2013 and 2012 (in thousands, except per share amounts):

	2014			2013			2012		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and Share Amounts	$(283,427)	43,795	$(6.47)	$(2,442)	43,331	$(0.06)	$21,701	42,840	$0.51
Dilutive Securities:									
Stock Options		—			—			90	
Restricted Stock Awards		—			—			244	
Diluted EPS:									
Net Income (Loss) and Assumed Share Conversions	$(283,427)	43,795	$(6.47)	$(2,442)	43,331	$(0.06)	$21,701	43,174	$0.50

Options to purchase approximately 1.3 million shares at an average exercise price of $34.02 were outstanding at December 31, 2014, while options to purchase approximately 1.5 million shares at an average exercise price of $33.38 were outstanding at December 31, 2013 and options to purchase approximately 1.6 million shares at an average exercise price of $33.13 were outstanding at December 31, 2012.

All of the 1.4 million, 1.6 million and 1.3 million stock options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2014, 2013 and 2012, respectively, as they were antidilutive.

For the years ended December 31, 2014 and 2013, 0.5 million and 0.3 million restricted stock awards were not included in the computation of Diluted EPS, as they would be antidilutive given the net loss. Approximately 0.3 million of restricted stock awards were not included in the computation of Diluted EPS for the year ended December 31, 2012 because they were antidilutive.

Approximately 0.4 million and 0.3 million shares related to performance-based restricted stock units that could be converted to common shares based on predetermined performance and market goals were not included in the computation of Diluted EPS for years ended December 31, 2014 and 2013, respectively, primarily because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

Table of Contents

3. Provision (Benefit) for Income Taxes

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

	Year Ended December 31,		
	2014	2013	2012
Income (Loss) Before Income Taxes	$(433,470)	$198	$37,773

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

	Year Ended December 31,		
	2014	2013	2012
Current	$314	$(12)	$(1,144)
Deferred	(150,357)	2,652	17,216
Total	$(150,043)	$2,640	$16,072

Reconciliations of income taxes computed using the U.S. Federal statutory rate (35%) to the effective income tax rates are as follows (in thousands):

	Year Ended December 31,		
	2014	2013	2012
Income taxes computed at U.S. statutory rate	$(151,714)	$69	$13,221
State tax provisions (benefits), net of federal benefits	(5,935)	(184)	(950)
Non-deductible equity compensation	666	1,127	1,911
Stock-based compensation tax shortfall	2,409	558	—
Valuation allowances	4,635	385	2,370
Expiration of carryover items	288	400	—
Uncertain Tax Positions	—	—	(977)
Other, net	(392)	285	497
Provision (benefit) for income taxes	$(150,043)	$2,640	$16,072
Effective rate	34.6 %	1,333.4 %	42.5 %

The Company’s operations are concentrated in Texas and Louisiana. The Company’s state tax provision varies in proportion to the overall statutory rate due to differences in deductions allowed for U.S. Federal and state income taxes.

In 2014 and 2013, the Company recorded tax expense of $2.4 million and $0.6 million, respectively, for stock-based compensation shortfalls. These shortfalls are for stock compensation grants on which the realized tax deduction was less than expense booked for these grants. Historically, the Company recorded excess tax benefits and shortfalls to paid-in-capital. However, during 2013 the Company exhausted its APIC Pool. The total tax effect of the shortfall for 2013 was $2.2 million, with $1.6 million being recorded as a reduction in paid-in-capital, and the remainder to tax expense. The entire shortfall for 2014 was recorded as tax expense.

The valuation allowances are primarily attributable to Louisiana net operating loss carryovers.

Table of Contents

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2014 and 2013 were as follows (in thousands):

	Year Ended December 31,	
	2014	2013
Deferred tax assets:		
Federal net operating loss ("NOL") carryovers	$ 141,896	$ 117,713
NOLs for excess stock-based compensation	(9,606)	(9,615)
State NOL carryovers	15,525	14,626
Alternative minimum tax credits	2,092	2,092
Other Carryover Items	1,294	1,295
Asset Retirement Obligations	26,388	28,628
Unrealized share-based compensation	9,471	9,957
Valuation allowance	(11,327)	(6,703)
Other	4,056	6,042
Total deferred tax assets	$ 179,789	$ 164,035
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ (258,326)	$ (393,606)
Other	(1,596)	(919)
Total deferred tax liabilities	$ (259,922)	$ (394,525)
Net deferred tax liabilities	$ (80,133)	$ (230,490)
Net current deferred tax assets	6,243	10,715
Net non-current deferred tax liabilities	$ (86,376)	$ (241,205)

The federal NOL carryovers totaling $405.4 million will expire between 2027 and 2034 if not utilized in earlier periods. Deferred tax benefits for excess stock-based compensation deductions represent stock-based compensation that have generated tax deductions that have not yet resulted in a cash tax benefit because the Company has NOL carryovers. The Company plans to recognize the federal NOL net deferred tax assets associated with excess stock-based compensation tax deductions only when all other components of the federal NOL carryover tax assets have been fully utilized. If and when the excess stock-based compensation related NOL carryover tax assets are realized, the benefit will be credited directly to equity. The state NOL carryovers are for Louisiana. The Louisiana loss carryovers are scheduled to expire between 2015 and 2029. The valuation allowances include $10.9 million and $6.6 million for 2014 and 2013, respectively for the Louisiana NOL carryovers.

U.S. Federal income tax returns for 2007 forward, Louisiana income tax returns from 1999 forward, New Zealand income tax returns after 2007, and Texas franchise tax returns after 2009 remain open to possible examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other jurisdiction returns are significant to our financial position.

As of December 31, 2014, we do not have any accrued liability for uncertain tax positions. We do not believe the total of unrecognized tax positions will significantly increase or decrease during the next 12 months.

4. Long-Term Debt

Our long-term debt as of December 31, 2014 and 2013, was as follows (in thousands):

	December 31, 2014	December 31, 2013
7.125% senior notes due in 2017	$ 250,000	$ 250,000
8.875% senior notes due in 2020 (1)	222,775	222,446
7.875% senior notes due in 2022 (1)	404,459	404,922
Bank Borrowings	197,300	265,000
Long-Term Debt (1)	$ 1,074,534	$ 1,142,368

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

As of December 31, 2014, our bank borrowings of $197.3 million mature in 2017. The maturities on our senior notes were $250.0 million in 2017, $225.0 million in 2020 and $400.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $5.0 million, $7.2 million and $7.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Bank Borrowings. On October 27, 2014, our syndicate of 11 banks reaffirmed the borrowing base of $417.6 million on our $500.0 million credit facility. The commitment amount of $417.6 million and maturity date of November 1, 2017 remained unchanged. Our next scheduled borrowing base redetermination is May 1, 2015.

The borrowing base may be affected by the performance of our oil and gas properties and changes in oil and natural gas prices. The pricing used by the banks to determine the borrowing base in future periods may be lower than the pricing used in October 2014, during our previous redetermination. The determination of the borrowing base is at the sole discretion of the administrative agent and the bank syndicate.

At December 31, 2014 and 2013, we had $197.3 million and $265.0 million in outstanding borrowings under our credit facility, respectively. The interest rate on our credit facility is either (a) the lead bank's prime rate plus an applicable margin or (b) the Eurodollar rate plus an applicable margin. However with respect to (a), if the lead bank's prime rate is not higher than each of the federal funds rate plus 0.5%, and the adjusted London Interbank Offered Rate ("LIBOR") plus 1%, the greatest of these three rates will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. During 2014, the lead bank's prime rate was 3.25% and the commitment fee associated with the credit facility fluctuated between 0.38% and 0.50%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, and limitations on incurring other debt. In addition, our bank credit agreement contains financial covenants detailing certain minimum financial ratios that must be maintained. The first is an adjusted working capital ratio of adjusted current assets to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0, which is below the Company's December 31, 2014 ratio of 1.9 to 1.0. There is also an interest coverage ratio, calculated on a trailing twelve month basis of EBITDAX to interest expense (as defined in the Credit Agreement), of no less than 2.75 to 1.0, which is below the Company's December 31, 2014 ratio of 4.9 to 1.0. Since inception, no cash dividends have been declared on our common stock. The terms of the credit facility also require us to secure at least 75% of our oil and natural gas properties. Under the terms of the credit facility, the commitment amount can be less than or equal to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. As of December 31, 2014, we were in compliance with the provisions of this agreement, and expect to remain in compliance throughout 2015.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $7.5 million, $6.0 million and $3.7 million for the years ended December 31, 2014, 2013 and 2012, respectively. The amount of commitment fees included in interest expense, net was $0.8 million, $1.1 million and $1.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

In prior periods, the Company presented the net change in its bank borrowings credit as a single line item within the financing activities section of the accompanying consolidated statements of cash flows. Beginning in 2014, the Company chose to correct this immaterial presentation error and began presenting bank borrowings and repayments on a gross basis. The financing activities section of the accompanying consolidated statements of cash flows for the 2013 and 2012 periods have been corrected for this

Table of Contents

immaterial error in presentation, which did not affect cash balances, total financing cash flows or any other subtotal on the accompanying consolidated statements of cash flows.

Senior Notes Due In 2022. These notes consist of $400.0 million of 7.875% senior notes that will mature on March 1, 2022. On November 30, 2011, we issued $250.0 million of these senior notes at a discount of $2.1 million or 99.156% of par, which equates to an effective yield to maturity of 8%. The original discount of $2.1 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. On October 3, 2012, we issued an additional $150.0 million of these senior notes at 105% of par, which equates to a yield to worst of 6.993%. The premium of $7.5 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on March 1 and September 1 and commenced on March 1, 2012. On or after March 1, 2017, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in annual intervals to 100% in 2020 and thereafter. In addition, prior to March 1, 2015, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $7.5 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2014.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $31.6 million for the years ended December 31, 2014 and 2013, and $22.4 million for the year ended December 31, 2012.

Senior Notes Due In 2020. These notes consist of $225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on January 15, 2010. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in annual intervals to 100% in 2018 and thereafter. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2014.

Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $20.8 million, $20.7 million and $20.6 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. As of December 31, 2014, we may redeem some or all of these notes, with certain restrictions, at a redemption price of 101.188% of the principal, plus accrued and unpaid interest, declining to 100% at June 1, 2015. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of December 31, 2014.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $18.3 million for the years ended December 31, 2014 and 2013, and $18.2 million for the year ended December 31, 2012.

5. Commitments and Contingencies

Rental and lease expenses were $21.0 million, $20.5 million and $19.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. The rental and lease expenses primarily relate to compressor rentals during the year and the lease of our office space in Houston, Texas, which was set to expire in February 2015. In January of 2015 the Company entered into a new eleven year lease agreement for office space in Houston, Texas. The operating lease commences on March 1, 2015 and may be terminated after seven years. The minimum contractual obligations are approximately $25 million in the aggregate. We will amortize the total payments under the lease agreement on a straight-line basis over the term of the lease.

Our remaining minimum annual obligations under non-cancelable operating lease commitments were $12.6 million for 2015, less than $0.1 million for 2016 and approximately $12.6 million in total. The remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to short-term compressor rental agreements.

Our employment agreement liabilities for certain named executive officers, as detailed in our most recent proxy statement, constitute the majority of other long-term liabilities on the balance sheet at both December 31, 2014 and 2013.

Our remaining gas transportation and processing minimum obligations were $12.7 million for 2015, $12.5 million for 2016, $10.1 million for 2017, $10.2 million for 2018, $8.7 million for 2019 and $61.6 million in the aggregate.

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

6. Share-Based Compensation

Share-Based Compensation Plans

We have multiple share-based compensation plans with outstanding awards including the 2005 Stock Compensation Plan, most recently amended by our Board of Directors in May 2013, which was approved by shareholders at the 2005 annual meeting of shareholders; the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders; the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants will be made under the 2001 Omnibus Stock Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the

2005 Stock Compensation Plan, although stock option awards remain outstanding under the plans and are accordingly included in the tables below. In addition, we have an employee stock purchase plan and an employee stock ownership plan. We follow guidance contained in FASB ASC 718 to account for share-based compensation.

Under the 2005 plan, stock option awards and other equity based awards may be granted to employees, directors, and consultants, with directors only eligible to receive restricted awards. Under the 2001 plan, stock option awards and other equity based awards were granted to employees. Under the 1990 non-qualified plan, non-employee members of our Board of Directors were automatically granted stock option awards to purchase shares of common stock on a formula basis. All three plans provide that the exercise prices for stock option awards equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested over a three year period, and stock option awards become exercisable in various terms ranging from one year to five years. Stock option awards granted typically expire ten years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock option awards are exercised, the cash received is credited to common stock and additional paid-in capital. The 2005 plan allows for the use of a “stock swap” in lieu of a cash exercise for stock option

Table of Contents

awards, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid “stock swap.” Stock option awards issued under a “stock swap” also previously included a reload feature that was discontinued during 2012. There were no mature shares that were delivered in “stock swap” transactions during 2014 while there were 10,752 and 20,692 for the years ended December 31, 2013 and 2012, respectively.

The employee stock purchase plan, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary, within IRS limitations and plan rules, during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year. Under this plan for the last three years, we have issued 71,825 shares at a price of $11.47 in 2014, 72,273 shares at a price of $13.08 in 2013 and 42,624 shares at a price of $25.26 in 2012. The contributions for the years ended December 31, 2014, 2013 and 2012 were all made in common stock. As of December 31, 2014, 318,027 shares remained available for issuance under this plan.

We receive a tax deduction for certain stock option exercises during the period the stock option awards are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards. We receive an additional tax deduction when restricted stock awards vest at a higher value than the value used to recognize compensation expense at the date of grant. We are required to report excess tax benefits from the award of equity instruments as financing cash flows. We recognized an excess tax shortfall for the years ended December 31, 2014 and 2013, as referenced in Note 3 of these consolidated financial statements. We did not recognize any material excess tax benefit or shortfall in earnings for the year ended December 31, 2012.

There were no stock option exercises for the year ended December 31, 2014. Net cash proceeds from the exercise of stock option awards were not material for the year ended December 31, 2013 and were $0.6 million for the year ended December 31, 2012. The actual income tax benefit from stock option exercises was $0.3 million for the year ended December 31, 2012.

Share-based compensation expense awards to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying consolidated statements of operations, was $6.7 million, $9.3 million and $12.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. Share-based compensation recorded in lease operating cost was $0.2 million for the year ended December 31, 2014 and $0.3 million for the years ended December 31, 2013 and 2012, respectively. We also capitalized $3.5 million, $5.5 million and $5.2 million of share-based compensation for the years ended December 31, 2014, 2013 and 2012, respectively. We view stock option awards and restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life of component awards and amortize the awards on a straight-line basis over the life of the awards.

Our shares available for future grant under our Share-Based Compensation plans were 1,814,928 at December 31, 2014. Each stock option award granted reduces the aforementioned total by 1.0 share, while each restricted stock award and restricted stock unit granted reduces the shares available for future grant by 1.44 shares.

Stock Option Awards

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

Twelve Months
Ended

	December 31, 2012
Dividend yield	0%
Expected volatility	61.2%
Risk-free interest rate	0.8%
Expected life of stock option awards (in years)	4.3
Weighted-average grant-date fair value	$15.71

During the years ended December 31, 2014 and 2013, we did not grant any stock option awards. The expected term for grants issued considers all relevant factors including historical and expected future employee exercise behavior. We have analyzed

Table of Contents

historical volatility and, based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our stock option awards.

At December 31, 2014, we had $0.1 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of 0.1 years. The following table represents stock option award activity for the year ended December 31, 2014:

	2014	
	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	1,488,314	$33.38
Options granted	—	$—
Options canceled	(156,124)	$27.68
Options exercised	—	$—
Options outstanding, end of period	1,332,190	$34.02
Options exercisable, end of period	1,230,019	$34.14

Our outstanding and exercisable stock option awards at December 31, 2014 had no intrinsic value since all outstanding stock option awards were out of the money. The weighted average remaining contract life of stock option awards outstanding and exercisable at December 31, 2014 was 4.7 years and 4.5 years, respectively. The total intrinsic value of stock option awards exercised for the years ended December 31, 2014 and 2013 was not material and was $0.9 million for the year ended December 31, 2012.

The following table summarizes information about stock option awards outstanding at December 31, 2014:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/14	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/14	Wtd. Avg. Exercise Price
$8.00 to $24.99	380,080	4.6	$19.91	380,080	$19.91
$25.00 to $45.00	952,110	4.8	$39.66	849,939	$40.50
$8.00 to $45.00	1,332,190	4.7	$34.02	1,230,019	$34.14

Restricted Stock Awards

For the years ended December 31, 2014, 2013 and 2012, the Company issued 747,400, 869,430 and 543,800 shares, respectively, of restricted stock to employees, consultants, and directors. These shares vest over three years and remain subject to forfeiture if vesting conditions are not met. The weighted average fair values of these shares when issued, for the years ended December 31, 2014, 2013 and 2012 were $11.55, $14.86 and $31.12 per share, respectively.

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2014, we had unrecognized compensation expense of $9.6 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.5 years. The grant date fair values of shares vested for the years ended December 31, 2014, 2013 and 2012 were $11.8 million, $12.8 million and $10.0 million, respectively.

The following table represents restricted stock award activity for the year ended December 31, 2014:

	2014	
	Shares	Wtd. Avg.

		Grant Price
Restricted shares outstanding, beginning of period	1,267,110	$ 21.54
Restricted shares granted	747,400	$ 11.55
Restricted shares canceled	(208,206)	$ 15.30
Restricted shares vested	(392,292)	$ 30.09
Restricted shares outstanding, end of period	1,414,012	$ 14.81

Table of Contents

Performance-Based Restricted Stock Units

For the years ended December 31, 2014 and 2013, the Company granted 185,250 and 189,700 of performance-based restricted stock units, respectively. These units contained predetermined market and performance conditions set by our compensation committee with a performance period of 3 years and a cliff vesting period of 3.1 years. The Target payout is 100% of the units granted while the conditions of the grants allow for a payout ranging between no payout and 200% of target.

The compensation expense for the market condition is based on the per unit grant date valuation using a Monte-Carlo simulation. The performance condition is remeasured quarterly and compensation expense is recorded based on the closing market price of our stock per unit on the grant date multiplied by the expected payout level. The payout level is calculated based on actual performance achieved during the performance period compared to a defined peer group.

As of December 31, 2014, we had unrecognized compensation expense of $2.2 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 1.8 years. No shares vested during the years ended December 31, 2014 and 2013. The weighted average grant date fair value for the restricted stock units granted during the years ended December 31, 2014 and 2013 was $11.68 and $15.01 per unit, respectively.

The following table represents restricted stock unit activity for the year ended December 31, 2014:

	Shares	Wtd. Avg. Grant Price
Restricted stock units outstanding, beginning of period	189,700	$ 15.01
Restricted stock units granted	185,250	$ 11.68
Restricted stock units canceled	—	$ —
Restricted stock units vested	—	$ —
Restricted stock units outstanding, end of period	374,950	$ 13.36

Employee Stock Ownership Plan

We established an Employee Stock Ownership Plan (“ESOP”) effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a three-year cliff vesting requirement. The ESOP is designed to enable our employees to accumulate stock ownership. While employees do not contribute to the plan, contributions made by Swift energy provide participants with an allocation of stock within the plan. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. No contributions will be made by Swift Energy for the year ended December 31, 2014. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2013 and 2012, were all made in common stock, from treasury shares, and are recorded as “General and administrative, net” on the accompanying consolidated statements of operations. The shares of common stock contributed to the ESOP plan, from treasury shares, totaled 14,815 and 12,995 for the years ended December 31, 2013 and 2012, respectively.

Employee Savings Plan

We have a savings plan under Section 401(k) of the Internal Revenue Code. In 2013 this plan was updated so that eligible employees may make voluntary contributions into the 401(k) savings plan with Swift Energy contributing on behalf of the eligible employee an amount equal to 100% of the first 6% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $1.8 million for the years ended December 31, 2014 and 2013, respectively, and were $1.5 million for the year ended December 31, 2012. These amounts were recorded as “General and administrative, net” on the accompanying consolidated statements of operations. The 2014 plan contributions were made with a combination of $0.9 million of cash and 352,476 shares of common stock, from treasury shares, while the 2013 and 2012 plan contributions were all made in common stock, from treasury shares. The shares of common stock contributed to the 401(k) savings plan totaled 139,850 and 91,895 for the years ended December 31, 2013 and 2012, respectively.

7. Related-Party Transactions

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the aunt of the Company's Chairman of the Board and Chief Executive

Officer. We paid Tec-Com, for services pursuant to the terms of the contract, approximately $0.6 million in 2014, 2013 and 2012. The contract was renewed on July 1, 2014 on substantially the same terms as the previous contract and expires June 30, 2015.

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

8. Acquisitions and Dispositions

On July 15, 2014, we closed our transaction with Saka Energi to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas, with an effective date of January 1, 2014. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi for $175 million in total cash consideration, with $125 million paid at closing (subject to adjustments for the interim period between the effective date and the closing date) and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date. As of December 31, 2014, approximately $29 million remained of Saka Energi's original $50 million carry obligation. At closing, the company received approximately $147 million in proceeds, including a $12.5 million deposit received during the prior quarter which was held in an escrow account until the closing date, as well as adjustments for the interim period between the effective date and the closing date. The proceeds initially were used to reduce our outstanding borrowings on our credit facility which were partially offset by additional borrowings against the credit facility during the second half of the year to fund development expenditures. No gain or loss was recognized for the transaction as the proceeds were applied to the full cost pool.

There were no material acquisitions in 2014, 2013 or 2012.

9. Fair Value Measurements

FASB ASC 820-10 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements.

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments.

Based upon quoted market prices as of December 31, 2014, 2013 and 2012, the fair value and carrying value of our senior notes was as follows (in millions):

	December 31, 2014		December 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$153.0	$250.0	$256.7	$250.0	$258.1	$250.0
8.875% senior notes due in 2020	$133.1	$222.8	$239.1	$222.4	$244.4	$221.1
7.875% senior notes due in 2022	$198.0	$404.5	$409.0	$404.9	$424.0	$405.4

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

60

The following table presents our assets that are measured at fair value as of December 31, 2014 and 2013, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 1 of these consolidated financial statements. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2014				
Assets				
Natural Gas Derivatives	$2.4	$—	$2.4	$—
Natural Gas Basis Derivatives	$0.1	$—	$0.1	$—
Liabilities				
Natural Gas Basis Derivatives	$0.1	$—	$0.1	$—
December 31, 2013				
Assets				
Natural Gas Derivatives	$0.5	$—	$0.5	$—
Oil Derivatives	$0.3	$—	$0.3	$—
Liabilities				
Natural Gas Derivatives	$0.7	$—	$0.7	$—
Oil Derivatives	$0.2	$—	$0.2	$—

Our derivative assets and liabilities in the table above are measured at gross fair value and are shown on the accompanying consolidated balance sheets in “Other current assets” and "Accounts payable and accrued liabilities", respectively.

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

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

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

10. Condensed Consolidating Financial Information

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

61

Table of Contents

Supplementary Information

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

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

	Total
December 31, 2014	
Proved oil and gas properties	$5,826,995
Unproved oil and gas properties	64,903
	5,891,898
Accumulated depreciation, depletion, and amortization	(3,803,080)
Net capitalized costs	$2,088,818
December 31, 2013	
Proved oil and gas properties	$5,600,279
Unproved oil and gas properties	71,452
	5,671,731
Accumulated depreciation, depletion, and amortization	(3,092,591)
Net capitalized costs	$2,579,140

There were $64.9 million of unproved property costs at December 31, 2014, excluded from the amortizable base. Of this amount, $30.5 million was incurred in 2014, $16.3 million was incurred in 2013, $5.6 million was incurred in 2012 and $12.5 million was incurred in prior years. We evaluate the majority of these unproved costs within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved oil and gas properties as of December 31, 2014 and 2013.

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

	Year Ended December 31,		
	2014	2013	2012
Lease acquisitions and prospect costs	$44,162	$46,555	$52,840
Exploration	—	5,279	—
Development (1) (3)	319,758	486,967	670,251
Total acquisition, exploration, and development (2)	$363,920	$538,801	$723,091

(1) Facility construction costs and capital costs have been included in development costs, and totaled $42.1 million, $63.9 million and $81.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

(2) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $26.3 million, $31.8 million and $31.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. In addition, the total includes $5.0 million, $7.2 million and $7.9 million for the years ended December 31, 2014, 2013 and 2012, respectively, of capitalized interest on unproved properties.

(3) Includes asset retirement obligations incurred, including revisions, of approximately ($11.8 million), ($2.8 million) and $5.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Table of Contents

Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were determined by us, and our reserves were audited by H. J. Gruy and Associates, Inc. (“Gruy”), independent petroleum consultants. Gruy has audited 97% of our proved reserves as of December 31, 2014 and 2013 and 96% of our proved reserves as of December 31, 2012.

Estimates of Proved Reserves	Total (Boe)	Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
Proved reserves as of December 31, 2012	192,072,642	597,568,985	43,258,614	49,219,197
Revisions of previous estimates (1)	(36,608,891)	(137,035,411)	6,203,299	(19,972,955)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place (4)	(775,552)	(1,802,335)	(231,266)	(243,897)
Extensions, discoveries, and other additions (3)	76,284,504	389,390,614	7,690,171	3,695,897
Production (5)	(11,745,635)	(32,996,993)	(3,926,323)	(2,319,813)
Proved reserves as of December 31, 2013	219,227,067	815,124,860	52,994,495	30,378,429
Revisions of previous estimates (1) (6)	(338,266)	35,340,785	(3,042,459)	(3,185,937)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place (4)	(30,879,608)	(185,248,104)	—	(4,924)
Extensions, discoveries, and other additions (3)	18,204,680	63,912,343	3,265,519	4,287,104
Production (5)	(12,387,440)	(42,382,798)	(3,511,297)	(1,812,345)
Proved reserves as of December 31, 2014 (6)	193,826,433	686,747,086	49,706,258	29,662,327
Proved developed reserves (2):				
December 31, 2012	65,714,713	195,642,512	17,779,798	15,327,830
December 31, 2013	62,912,871	197,815,575	16,884,760	13,058,849
December 31, 2014	66,285,034	232,806,911	14,989,353	12,494,529
Proved undeveloped reserves				
December 31, 2012	126,357,929	401,926,473	25,478,816	33,891,367
December 31, 2013	156,314,196	617,309,285	36,109,735	17,319,580
December 31, 2014	127,541,399	453,940,175	34,716,905	17,167,798

(1) Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, reservoir pressure and commodity pricing. The overall slight decrease in reserves due to revisions in 2014 were driven by generally offsetting performance-based adjustments in various fields and included downward revisions in the Central Louisiana area and upwards revisions in the Fasken area. The downward revisions in 2013 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 during 2013. These revisions were partially offset by net upward revisions in our other fields. Proved reserves, as of December 31, 2014, 2013 and 2012, were based upon the preceding 12-months' average price based on closing prices on the first business day of each month, or prices defined by existing contractual arrangements are held constant, for that year's reserves calculation. The 12-month 2014 average adjusted prices after differentials used in our calculations were $4.32 per Mcf of natural gas, $93.64 per barrel of oil, and $33.00 per barrel of NGL compared to $3.41 per Mcf of natural gas, $104.38 per barrel of oil, and $31.68 per barrel of NGL for the 12-month average 2013 prices and $2.71 per Mcf of natural gas, $103.64 per barrel of oil, and $46.22 per barrel of NGL for the 12-month average 2012 prices.

(2) At December 31, 2014, 2013 and 2012, 34%, 29% and 34% of our reserves were proved developed, respectively.
(3) We have added proved reserves primarily through our drilling activities, including 18.2 MMBoe added in 2014 and 76.3 MMBoe added in 2013. The 2014 proved reserves additions were driven primarily by proved undeveloped reserves additions associated with drilling operations conducted in the AWP Eagle Ford area. The 2013 proved

reserves additions consisted primarily of additions in the Fasken Eagle Ford area along with additions in the AWP Eagle Ford area.

(4) Includes the disposition of Fasken properties in July of 2014 and the disposition for our Brookeland field in May of 2013.

(5) Production volumes include 3,884 and 3,325 MMcf of natural gas consumed in operations for 2014 and 2013, respectively.

(6) The Company's reserves volumes have historically included gas consumed in operations. Effective in our December 31, 2014 reserves volumes, we have excluded natural gas volumes expected to be consumed in future operations from our ending reserves volumes. The effect of this change is included in the table above under Revision of previous estimates. This change does not impact our cash flow or PV10 projections as the prices are adjusted accordingly.

Table of Contents

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

	Year Ended December 31,		
	2014	2013	2012
Future gross revenues	$8,597,119	$9,276,386	$8,376,948
Future production costs	(2,447,318)	(2,373,832)	(2,257,087)
Future development costs (1)	(2,256,328)	(2,335,339)	(2,045,977)
Future net cash flows before income taxes	3,893,473	4,567,215	4,073,884
Future income taxes	(773,688)	(1,001,588)	(906,125)
Future net cash flows after income taxes	3,119,785	3,565,627	3,167,759
Discount at 10% per annum	(1,468,111)	(1,563,846)	(1,296,058)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$1,651,674	$2,001,781	$1,871,701

(1) These amounts include future costs related to asset retirement obligations.

The standardized measure of discounted future net cash flows from production of proved reserves for the year ended December 31, 2014, was developed as follows:

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

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

The following are the principal sources of changes in the standardized measure of discounted future net cash flows (in thousands) for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Beginning balance	$2,001,781	$1,871,701	$1,517,620
Revisions to reserves proved in prior years			
Net changes in prices, net of production costs	(208,597)	428,680	(156,121)
Net changes in future development costs	(19,651)	15,213	(22,300)
Net changes due to revisions in quantity estimates	(5,762)	(736,754)	7,060
Accretion of discount	242,464	228,406	191,761
Other	(236,996)	(136,615)	(72,269)
Total revisions	(228,542)	(201,070)	(51,869)
New field discoveries and extensions, net of future production and development costs	38,301	503,604	663,572

Purchases of minerals in place	—	—	—
Sales of minerals in place	(128,939)	6,724	—
Sales of oil and gas produced, net of production costs	(396,399)	(422,691)	(389,862)
Previously estimated development costs incurred	234,184	254,022	144,606
Net change in income taxes	131,288	(10,509)	(12,366)
Net change in standardized measure of discounted future net cash flows	(350,107)	130,080	354,081
Ending balance	$1,651,674	$2,001,781	$1,871,701

Table of Contents

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2014 and 2013 (in thousands, except per share data):

	Revenues	Net Income (Loss) Before Taxes	Net Income (Loss)	Basic EPS	Diluted EPS
2014					
First	$144,180	$11,707	$5,442	$0.12	$0.12
Second	155,994	11,761	6,827	0.16	0.15
Third	138,794	5,475	2,474	0.06	0.06
Fourth (1)	110,488	(462,413)	(298,170)	(6.80)	(6.80)
Total	$549,456	$(433,470)	$(283,427)	$(6.47)	$(6.47)
2013					
First	$146,291	$12,886	$8,038	$0.19	$0.18
Second	144,077	12,311	7,549	0.17	0.17
Third	150,933	12,984	7,359	0.17	0.17
Fourth (1)	143,100	(37,983)	(25,388)	(0.58)	(0.58)
Total	$584,401	$198	$(2,442)	$(0.06)	$(0.06)

(1) Due to the effects of pricing, timing of projects and changes in our reserves product mix, in the fourth quarter of 2014 and 2013, we reported non-cash write-downs on a before-tax basis of $445.4 million ($287.3 million after tax) and $46.9 million ($30.0 million after tax), respectively, on our oil and natural gas properties.

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

Table of Contents

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

None.

Item 9A. Controls and Procedures

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

As disclosed in our Form 10-K/A for the year ended December 31, 2013, during the third quarter of 2014 management determined that a deficiency in internal control over financial reporting existed related to the review of the full-cost ceiling test write-down calculation. The deficiency specifically related to the deferred income tax effects attributable to the Company’s asset retirement obligations. Management has also concluded that this deficiency was a material weakness, as defined by Securities and Exchange Commission regulations, and that our disclosure controls and procedures were not effective as of December 31, 2013 as a result of the material weakness in our internal control over financial reporting.

Remediation

We completed our remediation efforts related to this material weakness by, among other things, implementing a process of enhanced review of the non-cash ceiling test calculation in the fourth quarter of 2014. The actions that were taken were subject to senior management review and Audit Committee oversight. Management believes the foregoing efforts have effectively remediated the material weakness in the fourth quarter of 2014.

Management's Report on Internal Control Over Financial Reporting as of December 31, 2014 is included in Item 8. Financial Statements and Supplementary Data. The Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting is also included in Item 8.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 19, 2015, annual shareholders' meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 19, 2015, annual shareholders' meeting is incorporated herein by reference.

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

The information required under Item 12 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 19, 2015, annual shareholders' meeting is incorporated herein by reference.

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

The information required under Item 13 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 19, 2015, annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 19, 2015, annual shareholders' meeting is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated March 2, 2015, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

67

Table of Contents

3. Exhibits

3.1	Restated Certificate of Formation of Swift Energy Company (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009 filed November 3, 2009, File No. 1-08754).
3.2	Amendment No. 1 to the Company's Restated Certificate of Formation (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Form 8-K filed May16, 2011, File No. 1-08754).
3.3	Fourth Amended and Restated Bylaws of Swift Energy Company, effective July 30, 2013 (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Quarterly Report on Form 10-Q filed August 1, 2013, File No. 1-08754).
3.4	Certificate of Designation of Series A Junior Participating Preferred Stock of Swift Energy Company (incorporated by reference as Exhibit 3.4 to Swift Energy Company's Form 8-K filed December 29, 2005, File No. 1-08754).
4.1	Indenture dated as of May 16, 2007 between Swift Energy Company and Wells Fargo Bank, National Association (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Registration Statement on Form S-3 filed May 17, 2007, File No. 333-143034).
4.2	First Supplemental Indenture dated as of June 1, 2007, between Swift Energy Company, Swift Energy Operating, LLC and Wells Fargo Bank, National Association relating to the 7-1/8% Senior Notes due 2017 (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed June 7, 2007, File No. 1-08754).
4.3	Indenture dated as of May 19, 2009, between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Registration Statement on Form S-3 filed May 19, 2009, and amended June 17 and June 26, 2009, File No. 333-159341).
4.4	First Supplemental Indenture dated as of November 25, 2009, between Swift Energy Company, Swift Energy Operating, LLC, and Wells Fargo Bank, National Association, as Trustee, including the form of 8 7/8% Senior Notes (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 2, 2009, File No. 1-08754).
4.5	Second Supplemental Indenture dated as of November 30, 2011, among Swift Energy Company, Swift Energy Operating, LLC, and Wells Fargo Bank, National Association relating to the 7-7/8% Senior Notes due 2022 of Swift Energy Company (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form 8-K filed December 5, 2011, File No. 1-08754).
4.6	Registration Rights Agreement, dated October 18, 2012, by and among Swift Energy Company, Swift Energy Operating, LLC and J.P. Morgan Securities LLC, as representatives of the initial purchasers (incorporated by reference as Exhibit 4.3 to Swift Energy Company's Form 8-K filed October 24, 2012, File No. 1-08754).
10.1+	2001 Omnibus Stock Compensation Plan, as of January 1, 2001 (incorporated by reference as Exhibit 4.3 to the Swift Energy Company's Registration Statement on Form S-8 filed August 10, 2001, File No. 333-67242).

10.2+	Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan dated February 12, 2013 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 24, 2013, File No. 1-08754).
10.3+	Amendment No. 1 to the Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan dated May 20, 2014 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 27, 2014, File No. 1-08754).
10.4+	Forms of agreements for grant of incentive stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.19 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005 filed March 2, 2006, File No. 1-08754).
10.5+	Form of Indemnity Agreement for Swift Energy Company officers (incorporated by reference as Exhibit 10.9 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 filed March 1, 2007, File No. 1-08754).
10.6+	Form of Indemnity Agreement for Swift Energy Company directors (incorporated by reference as Exhibit 10.10 to Swift Energy Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 filed February 28, 2007, File No. 1-08754).
10.7+	Consulting Agreement between Swift Energy Company and Virgil N. Swift effective as of July 1, 2006 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2006 filed May 5, 2006, File No. 1-08754).

Table of Contents

10.8	Second Amended and Restated Credit Agreement as of September 21, 2010, among Swift Energy Company, Swift Energy Operating, LLC and JPMorgan Chase Bank, N.A. as Administrative Agent, BNP Paribas and Wells Fargo Bank, N.A. as Co-Syndication Agents, Bank of Scotland PLC and Societe Generale, as Co-Documentation Agents, and the Lenders party thereto (incorporated by reference as Exhibit 10.01 to the Swift Energy Company's Form 8-K filed September 27, 2010, File No. 1-08754).
10.9	First Amendment and Consent to Second Amended and Restated Credit Agreement dated May 12, 2011, among Swift Energy Company, Swift Energy Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 17, 2011, File No. 1-08754).
10.1	Second Amendment to Second Amended and Restated Credit Agreement effective as of October 2, 2012, among Swift Energy Company, Swift Energy Operating, LLC and JPMorgan Chase Bank, N.A. as Administrative Agent, and the Lenders party thereto (incorporated by reference as Exhibit 10.1 to the Swift Energy Company's Form 8-K filed October 3, 2012, File No 1-08754).
10.11	Third Amendment to Second Amended and Restated Credit Agreement effective as of October 3, 2012, among Swift Energy Company, Swift Energy Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed November 5, 2012, File No. 1-08754).
10.12	Fourth Amendment and Consent to Second Amended and Restated Credit Agreement effective as of April 30, 2014, among Swift Energy Company, Swift Energy Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014, File No. 1-08754).
10.13+	Swift Energy Company Change of Control Severance Plan dated November 4, 2008 (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008).
10.14+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Terry E. Swift dated November 4, 2008 (incorporated by reference as Exhibit 10.3 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008, File No. 1-08754).
10.15+	Second Amended and Restated Executive Employment Agreement between Swift Energy Company and Alton D. Heckaman dated November 4, 2008 (incorporated by reference as Exhibit 10.5 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008, File No. 1-08754).
10.16+	Executive Employment Agreement between Swift Energy Company and Robert J. Banks dated November 4, 2008 (incorporated by reference as Exhibit 10.6 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008, File No. 1-08754).
10.17+	Amended and Restated Executive Employment Agreement between Swift Energy Company and James P. Mitchell dated November 4, 2008 (incorporated by reference as Exhibit 10.8 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008 filed November 6, 2008, File No. 1-08754).

10.18	Purchase Agreement, dated October 3, 2012 among Swift Energy Company, Swift Energy Operating, LLC and J.P. Morgan Securities LLC, as representatives of the several initial purchasers (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed October 5, 2012, File No. 1-08745).
10.19+	Form of Performance Restricted Stock Unit Award under the Second Amended and Restated Swift Energy 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013 filed May 2, 2013, File No. 1-08754).
10.20	Acquisition Agreement by and between Swift Energy Operating, LLC and Saka Energi Fasken, LLC executed May 5, 2014, but effective July 15, 2014 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30,2014, File No. 1-08754).
10.21+*	Retirement and Release Agreement between Swift Energy Company and Bruce H. Vincent dated January 8, 2015, but effective February 15, 2015.
12 *	Swift Energy Company Ratio of Earnings to Fixed Charges.
21 *	List of Subsidiaries of Swift Energy Company.
23.1 *	Consent of H.J. Gruy and Associates, Inc.

Table of Contents

23.2 *	Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-3, S-4 and S-8 Registration Statements.
31.1 *	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	The reserves audit letter of H.J. Gruy and Associates, Inc. dated February 4, 2015.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

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

Table of Contents

SIGNATURES

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

SWIFT ENERGY COMPANY

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant, Swift Energy Company, and in the capacities and on the dates indicated:

Signatures	Title	Date
/s/ Terry E. Swift Terry E. Swift	Director Chief Executive Officer President	March 2, 2015
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice President Chief Financial Officer Principal Accounting Officer	March 2, 2015
/s/ Deanna L. Cannon Deanna L. Cannon	Director	March 2, 2015
/s/ Douglas J. Lanier Douglas J. Lanier	Director	March 2, 2015
/s/Greg Matiuk Greg Matiuk	Director	March 2, 2015
/s/ Clyde W. Smith, Jr. Clyde W. Smith, Jr.	Director	March 2, 2015
/s/ Charles J. Swindells Charles J. Swindells	Director	March 2, 2015
/s/ Ronald L. Saxton Ronald L. Saxton	Director	March 2, 2015
/s/ William A. Bruckmann III William A. Bruckmann III	Director	March 2, 2015

71