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.
þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ Accelerated filer 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 |

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).

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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 | | | |