Swift Energy Company
2016 Annual Report

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, 2016

Commission File Number 1-8754

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

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

575 North Dairy Ashford, Suite 1200
Houston, Texas 77079
(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	OTCQX Best Market

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 ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934.

Yes ☐ No ☑

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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

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

☐

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 ☐ Accelerated filer ☑ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑

The aggregate public float of common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as quoted on the OTCQX Market as of June 30, 2016, the last business day of June 2016, was approximately $124,874,291.

The number of shares of common stock outstanding as of February 24, 2017 was 11,465,688.

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.

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 26 and 27 for explanations of abbreviations and terms used herein.

Overview

Swift Energy Company 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. We operate essentially all 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 geological trends where we operate. As a result of the significant resource potential from our properties in the Eagle Ford, we plan to invest nearly all of our total 2017 planned capital expenditures in this area.

At December 31, 2016, we had estimated proved reserves of 124.0 MMBoe with Standardized Measure of $407 million and PV-10 Value of $442 million (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 standardized measure of discounted future net cash flows, the closest GAAP measure). This is an increase of approximately 54 MMBoe from year-end 2015 proved reserves quantities due to additions of undeveloped reserves which were previously not included in our year-end 2015 proved reserves because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing. This increase was partially offset by the loss of proved reserves from the sale of our Louisiana and other properties. Our total proved reserves at December 31, 2016 were approximately 5% crude oil, 84% natural gas, and 11% NGLs while 51% of our total proved reserves were developed. All of our proved reserves are located in Texas.

Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On December 31, 2015, we and eight of our U.S. subsidiaries (the "Chapter 11 Subsidiaries") filed voluntary petitions seeking relief under Chapter 11 of Title 11 of the U.S. Bankruptcy Code (the "Bankruptcy Code") in the U.S. Bankruptcy Court for the District of Delaware under the caption *In re Swift Energy Company, et al* (Case No. 15-12670). The Company and the Chapter 11 Subsidiaries received bankruptcy court confirmation of their joint plan of reorganization (the "Plan") on March 31, 2016, and subsequently emerged from bankruptcy on April 22, 2016 (the "Effective Date"). References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 22, 2016. References to "Predecessor" or "Predecessor Company" refer to the financial position and results of operations of the Company prior to and including April 22, 2016. For a further description of these matters, see Note 1A in this Form 10-K in our Consolidated Financial Statements.

Business Strategy

Our business strategy is primarily focused on exploiting our unconventional reserves from our Fasken and other Eagle Ford fields.

- *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 first acquired producing Olmos properties in our AWP field in 1989. This area has remained a cornerstone of our operations since we first began drilling here in 1994. While the combination of proven drilling and completion technologies have allowed us to exploit the Eagle Ford shale, we have applied the same methods to further develop the "mature" Olmos sand. 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. 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. Our 2017 plans include completing nine wells in our Fasken field in Webb County, drilling and completing two wells in our AWP acreage in McMullen County, and drilling and completing our first well in Oro Grande in LaSalle County.

- *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.

- *Experienced technical team.* We employ 19 oil and gas technical professionals, including geophysicists, geologists, drilling production and reservoir engineers, and other oil and gas professionals who have an average of approximately 21 years of experience in their technical fields and have been employed by us for an average of approximately eight 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 focused in three fields located in South Texas. The following table sets forth information regarding our 2016 year-end proved reserves of 124.0 MMBoe and production of 9.2 MMBoe by area:

Fields	Proved Developed Reserves (MMBoe)	Proved Undeveloped Reserves (MMBoe)	Total Proved Reserves (MMBoe)	% of Total Proved Reserves	Oil and NGLs as % of Proved Reserves	Total Production (MBoe)
Artesia Wells	5.0	7.4	12.4	10.0 %	52.0 %	741
AWP	19.4	17.1	36.5	29.4 %	35.7 %	2,930
Fasken	38.5	36.4	74.9	60.4 %	— %	4,675
Other (1)	0.2	—	0.2	0.2 %	23.0 %	826
Total	**63.1**	**60.9**	**124.0**	**100.0%**	**15.7%**	**9,172**

(1) Primarily fields sold during the year including our former Lake Washington, South Bearhead Creek and Burr Ferry fields.

Fasken During 2016, the Company completed 11 wells in Fasken targeting the Eagle Ford formation. All wells in this field are operated by Swift Energy. Our reserves in this Eagle Ford formation are 100% natural gas. At December 31, 2016, we had 4 wells that were drilled and waiting on completion and we were in the process of drilling an additional 5 well pad to be completed in 2017.

AWP All wells in this field are operated by Swift Energy. Our proved reserves are in the Olmos and lower Eagle Ford formations. Our reserves in the Eagle Ford formation are 65% natural gas, 25% NGLs, and 9% oil on a Boe basis while our reserves in the Olmos formation are approximately 61% natural gas, 28% NGLs, and 11% oil on a Boe basis.

Artesia Wells Our December 31, 2016 proved reserves in this formation are 48% natural gas, 34% NGLs, and 18% oil on a Boe basis.

Other The Company completed a series of transactions that resulted in the disposition of virtually all of our producing fields in Louisiana and non-core Texas properties during 2016. The Company retained the abandonment obligations for its Bay de Chene Field in Louisiana. All wells in this field are currently shut in. See Note 10 of the consolidated financial statements in this Form 10-K for further discussion of these transactions.

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, 2016, 2015 and 2014. The information set forth in the tables regarding reserves is based on proved reserves reports prepared in accordance with SEC rules. H.J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers, prepared our proved reserves report as of December 31, 2016 and audited 99% and 97% of our proved reserves as of December 31, 2015 and 2014, respectively. Our 2015 and 2014 reserves reports were prepared internally under the supervision of our Chief Reservoir Engineer. The 2015 and 2014 reserves audits by H.J. Gruy and Associates, Inc. conformed to the meaning of the term “reserves audit” as presented in Regulation S-K, Item 1202. Reserve data used for interim reporting periods was prepared internally and was not audited.

The reserves estimation process involves members of the reserves and evaluation department who report to the Chief Reservoir Engineer. The staff includes engineers whose duty is to prepare estimates of reserves in accordance with the Commission's rules, regulations and guidelines. This team worked closely with H. J. Gruy and Associates to ensure the accuracy and completeness of the data utilized for the preparation of the 2016 reserve report. All information from our secure engineering database as well as geographic maps, well logs, production tests and other pertinent data was provided to the external engineers.

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 quarterly. The Board of Directors reviews the reserve data periodically and the independent Board members meet with H.J. Gruy and Associates, Inc. in executive session at least annually.

The technical person at H.J. Gruy and Associates, Inc. primarily responsible for overseeing preparation of the 2016 reserves report and the audits of prior year reports, 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 in preparing reserves reports and overseeing reserves audits.

Our Chief Reservoir Engineer, the primary technical person responsible for overseeing the preparation of our 2016 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.

Estimates of future net revenues from our proved reserves, Standardized Measure and PV-10 (PV-10 is a non-GAAP measure defined below), as of December 31, 2016, 2015 and 2014 are made in accordance with SEC criteria, which is 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 SEC proved reserve volumes, year-end Standardized Measure and PV-10. The 12-month 2016 average adjusted prices after differentials were $2.43 per Mcf of natural gas, $41.07 per barrel of oil, and $16.13 per barrel of NGL, compared to $2.61 per Mcf of natural gas, $49.58 per barrel of oil, and $14.64 per barrel of NGL for 2015 and $4.32 per Mcf of natural gas, $93.64 per barrel of oil, and $33.00 per barrel of NGL for 2014.

As noted above, PV-10 Value is a non-GAAP measure. The most directly comparable 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 without regard to the owner's income tax position. We use the PV-10 Value 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 any GAAP measure. Our PV-10 Value and the Standardized Measure do not purport to represent the fair value of our proved oil and natural gas reserves.

The following table provides a reconciliation between the Standardized Measure and PV-10 Value of the Company's proved reserves.

	As of December 31,		
(in millions)	**2016**	**2015**	**2014**
Standardized Measure of Discounted Future Net Cash Flows	**$ 407**	**$ 374**	**$ 1,652**
Future income taxes (discounted at 10%)	35	—	292
PV-10 Value	**$ 442**	**$ 374**	**$ 1,944**

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 presented on a Standardized Measure and PV-10 basis as of December 31, 2016, 2015 and 2014. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues.

At December 31, 2016, we had estimated proved reserves of 124.0 MMBoe with a Standardized Measure of $407 million and PV-10 Value of $442 million. This is a net increase of approximately 54 MMBoe from year-end 2015 proved reserves due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing. This increase was partially offset by the loss of proved reserves resulting from the sale of our Louisiana and other properties. Our total proved reserves at December 31, 2016 were approximately 5% crude oil, 84% natural gas, and 11% NGLs, while 51% of our total proved reserves were developed. All of our proved reserves are located in Texas. 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,**		
	2016	**2015**	**2014**
Natural gas reserves (MMcf):			
Proved developed	312,125	238,356	232,807
Proved undeveloped (3)	314,664	73,332	453,940
Total	626,789	311,688	686,747
Oil reserves (MBbl):			
Proved developed	4,513	10,109	14,989
Proved undeveloped (3)	1,265	—	34,717
Total	5,778	10,109	49,706
NGL reserves (MBbl):			
Proved developed	6,505	6,500	12,495
Proved undeveloped (3)	7,209	1,716	17,168
Total	13,714	8,216	29,663
Total Estimated Reserves (MBoe) (1)(3)	**123,957**	**70,273**	**193,826**
Standardized Measure of Discounted Future Net Cash Flows (in millions) (2)	**$ 407**	**$ 374**	**$ 1,652**
PV-10 by reserve category			
Proved developed	$ 252	$ 321	$ 954
Proved undeveloped	190	53	990
Total PV-10 Value (2)	**$ 442**	**$ 374**	**$ 1,944**

(1) The reserve volumes exclude natural gas consumed in operations.
(2) The Standardized Measure and PV-10 Values as of December 31, 2016, 2015 and 2014 are net of $33.1 million, $57.8 million and $85.5 million of plugging and abandonment costs, respectively.
(3) The decrease in 2015 reserves volumes was due to the impact of lower commodity prices and uncertainties, due in part to our bankruptcy filing, surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves.

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.

Proved Undeveloped Reserves

The following table sets forth the aging of our proved undeveloped reserves as of December 31, 2016:

Year Added	Volume (MMBoe)	% of PUD Volumes
2016 (1)	60.9	100 %
2015	0.0	— %
2014	0.0	— %
2013	0.0	— %
2012	0.0	— %
Total	**60.9**	**100%**

(1) The Company did not carry proved undeveloped reserves forward through bankruptcy except for locations that were converted to developed reserves early in 2016, therefore all proved undeveloped reserves were 2016 additions.

During 2016, our proved undeveloped reserves increased by approximately 47 MMBoe primarily due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing, partially offset by 2015 undeveloped reserves which were converted to proved developed reserves during 2016. We also incurred approximately $29 million in capital expenditures during the year which resulted in the conversion of 14 MMBoe of our December 31, 2015 proved undeveloped reserves to proved developed reserves, primarily in the Fasken field.

The PV-10 Value from our proved undeveloped reserves was $190 million at December 31, 2016, which was approximately 43% of our total PV-10 Value of $442 million. The PV-10 Value of our proved undeveloped reserves, by year of booking was 100% in 2016.

Sensitivity of Reserves to Pricing

As of December 31, 2016, a 5% increase in oil and NGL pricing would increase our total estimated proved reserves of 124.0 MMBoe by approximately 0.4 MMBoe, and would increase the PV-10 Value of $442 million by approximately $12 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 $12 million.

As of December 31, 2016, a 5% increase in natural gas pricing would increase our total estimated proved reserves by approximately 0.7 MMBoe and would increase the PV-10 Value by approximately $37 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated proved reserves by approximately 0.7 MMBoe and would decrease the PV-10 Value by approximately $37 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, 2016			
Gross	175	604	779
Net	172.1	558.7	730.8
December 31, 2015			
Gross	327	729	1,056
Net	308.9	682.7	991.6
December 31, 2014			
Gross	348	717	1,065
Net	330.3	673.9	1,004.2

(1) Excludes 9, 48 and 49 service wells in 2016, 2015 and 2014.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2016:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Texas (1)	63,054	58,970	32,249	30,605
Colorado(2)	—	—	30,897	29,971
Louisiana (3)	5,084	4,775	4,920	4,478
Wyoming	—	—	3,092	1,521
Total	**68,138**	**63,745**	**71,158**	**66,575**

(1) 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 38,254 gross and 30,874 net developed acres and 35,435 gross and 33,511 net undeveloped acres. A large portion of our undeveloped Eagle Ford acreage underlies developed Olmos acreage. In the Olmos, we have 44,812 gross and 41,700 net developed acres and 17,444 gross and 15,377 net undeveloped acres.

(2) The Company's leasehold acreage in Colorado is exploration property which is evaluated, inactive and will expire in 2017 and 2018 unless otherwise drilled, sold or farmed out.

(3) The above table includes acreage where Swift Energy is the fee mineral owner as well as a working interest owner. This fee mineral acreage included in the above table totals 3,644 gross and 1,535 net undeveloped acres and 942 gross and 532 net developed acres.

As of December 31, 2016, Swift Energy's net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 54% in 2017, 31% in 2018 and 6% in 2019. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options. As of February 27, 2017, 3,155 net undeveloped acres have expired during 2017. The exploration potential of all undeveloped acreage is fully evaluated before expiration. In each fiscal year where undeveloped acreage is subject to expiration (except for Colorado acreage) 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, 2016, 2015 and 2014:

		Gross Wells			Net Wells		
Year	**Type of Well**	**Total**	**Producing**	**Dry**	**Total**	**Producing**	**Dry**
2016	Exploratory	—	—	—	—	—	—
	Development	8	8	—	5.1	5.1	—
2015	Exploratory	—	—	—	—	—	—
	Development	24	24	—	17.1	17.1	—
2014	Exploratory	—	—	—	—	—	—
	Development	36	36	—	31.5	31.5	—

Recent Activities

As of December 31, 2016, we were in the process of drilling five wells in our Fasken field where we have a 64% working interest. In the first quarter of 2017, we have begun the process of conducting completion operations for 3 wells (approximately 2 net wells) drilled during the fourth quarter of 2016. In addition, we have initiated production on 4 wells that were drilled and completed in the fourth quarter of 2016.

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 accounted for in accordance with Council of Petroleum Accountants Societies' 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 for the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor) totaled \$4.5 million and \$2.7 million, respectively, and ranged from \$242 to \$2,029 per well per month.

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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), Shell Oil Company and affiliates accounted for 15%, 19%, 16% and 21%, respectively, of our sales proceeds, Kinder Morgan accounted for approximately 38%, 20%, 27% and 20%, respectively, of our sales proceeds and Plains Marketing accounted for approximately 14%, 14%, 18% and 11%, respectively, of our sales proceeds. Howard Energy accounted for approximately 11% and 13% of our sales proceeds during the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively, and did not account for sales proceeds above 10% for the period of April 23, 2016 through December 31, 2016 (successor) or the year ended December 31, 2014 (predecessor). Southcross Energy accounted for approximately 11% of our sales proceeds during the period of January 1, 2016 through April 22, 2016 (predecessor) and did not account for sales proceeds above 10% during the period of April 23, 2016 through December 31, 2016 (successor) or the years ended December 31, 2015 and 2014 (predecessor).

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 Products. Oil production is transported to market by truck and sold at prevailing market prices.

We have a gas gathering agreement with Howard Energy providing for the transportation of our Eagle Ford production on the pipeline from Fasken to Kinder Morgan Texas Pipeline or Eagle Ford Midstream, 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.

We have 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 Targa (formerly 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.

Prior to our disposition of the field, oil production from Lake Washington was either delivered into ExxonMobil's crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices. Historically, our natural gas production from this field was either consumed on the lease or was delivered to High Point Gas Transmission (successor to El Paso's Southern Natural Gas Company) pipeline system and the processing of natural gas occurred at the Toca Plant.

The prices in the tables below do not include the effects of hedging. Quarterly prices are detailed under "Results of Operations – Revenues" in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in 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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor).

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31,	
All Fields			**2015**	**2014**
Net Sales Volume:				
Oil (MBbls)	786	522	2,406	3,511
Natural Gas Liquids (MBbls)	727	380	1,433	1,812
Natural gas (MMcf)	29,109	11,431	43,839	37,685
Total (MBoe)	6,365	2,807	11,146	11,604
Average Sales Price:				
Oil (Per Bbl)	$ 44.79	$ 31.43	$ 47.11	$ 92.74
Natural Gas Liquids (Per Bbl)	$ 16.39	$ 11.04	$ 14.54	$ 31.83
Natural gas (Per Mcf)	$ 2.55	$ 1.96	$ 2.56	$ 4.36
Total (Per Boe)	$ 19.07	$ 15.33	$ 22.09	$ 47.20
Average Production Cost (Per Boe sold) (1)	$ 6.01	$ 7.57	$ 8.25	$ 9.85

(1) 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 90% of the Company's proved reserves based on total Boe as of December 31, 2016:

Fasken	Successor		Predecessor				
	Period from April 23, 2016 through December 31, 2016		Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015		2014	
Net Sales Volume:							
Natural Gas Liquids (MBbls)		1	1		2		3
Natural gas (MMcf) (1)		20,762	7,274		28,598		21,080
Total (MBoe)		3,462	1,213		4,768		3,516
Average Sales Price:							
Natural Gas Liquids (Per Bbl)	$	14.09	$ 3.87	$	16.65	$	32.44
Natural gas (Per Mcf)	$	2.55	$ 1.96	$	2.53	$	4.14
Total (Per Boe)	$	15.30	$ 11.77	$	15.16	$	24.84
Average Production Cost (Per Boe sold) (2)	$	3.34	$ 3.47	$	3.20	$	3.70

(1) Excludes natural gas consumed in operations.
(2) Average production cost includes transportation and gas processing costs but excludes severance and ad valorem taxes.

AWP	Successor		Predecessor				
	Period from April 23, 2016 through December 31, 2016		Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015		2014	
Net Sales Volume:							
Oil (MBbls)		388	206		1,047		1,655
Natural Gas Liquids (MBbls)		519	235		843		968
Natural gas (MMcf) (1)		6,438	3,061		10,372		10,057
Total (MBoe)		1,980	951		3,618		4,299
Average Sales Price:							
Oil (Per Bbl)	$	44.54	$ 30.07	$	45.37	$	89.86
Natural Gas Liquids (Per Bbl)	$	16.32	$ 11.31	$	14.79	$	30.72
Natural gas (Per Mcf)	$	2.59	$ 1.90	$	2.62	$	4.61
Total (Per Boe)	$	21.41	$ 15.43	$	24.08	$	52.29
Average Production Cost (Per Boe sold) (2)	$	6.20	$ 7.85	$	8.64	$	9.23

(1) Excludes natural gas consumed in operations.
(2) Average production cost includes transportation and gas processing costs but excludes severance and ad valorem taxes.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and natural gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or individual injuries. The oil and natural gas exploration business is also subject to environmental hazards, such as oil spills, natural gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. 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. The Company has derivative instruments in place to protect a significant portion of our production against declines in oil and natural gas prices through the first quarter of 2018. For additional discussion related to our price-risk policy, refer to Note 6 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.

Employees

As of December 31, 2016, the Company employed 151 people. The Company is currently implementing a reduction-in-force under the Worker Adjustment and Retraining Notification ("WARN") Act. We expect to have slightly fewer than 100 employees after March 2017, which will be a result of the completion of the reduction-in-force and other unrelated terminations that have occurred since December 31, 2016. None of our employees were represented by a union and relations with employees are considered to be good.

Facilities

Prior to December 31, 2016, we executed a sub-lease agreement for 27,259 square feet of new office space at 575 N. Dairy Ashford Road, Houston, Texas. We relocated our headquarters to this location in January 2017. For discussion regarding the term and obligations of this sub-lease refer to Note 7 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

Risks Related to our Emergence from Chapter 11 Bankruptcy

We emerged from bankruptcy on April 22, 2016, which could adversely affect our business and relationships.

It is possible that our having filed for bankruptcy and our emergence from the Chapter 11 bankruptcy proceedings could adversely affect our business and relationships with customers, employees and suppliers. Due to uncertainties, many risks exist, including the following:

- key suppliers could terminate their relationship or require financial assurances or enhanced performance;
- the ability to renew existing contracts and compete for new business may be adversely affected;
- the ability to attract, motivate and/or retain key executives and employees may be adversely affected;
- employees may be distracted from performance of their duties or more easily attracted to other employment opportunities; and
- competitors may take business away from us, and our ability to attract and retain customers may be negatively impacted.

The occurrence of one or more of these events could have a material and adverse effect on our operations, financial condition and reputation. We cannot assure you that having been subject to bankruptcy protection will not adversely affect our operations in the future.

Our actual financial results after emergence from bankruptcy will not be comparable to our historical financial information as a result of the implementation of the plan of reorganization and the transactions contemplated thereby and our adoption of fresh start accounting.

In connection with the disclosure statement we filed with the bankruptcy court, and the hearing to consider confirmation of the plan of reorganization, we prepared projected financial information to demonstrate to the bankruptcy court the feasibility of the plan of reorganization and our ability to continue operations upon our emergence from bankruptcy. Those projections were prepared solely for the purpose of the bankruptcy proceedings and have not been, and will not be, updated on an ongoing basis and should not be relied upon by investors. At the time they were prepared, the projections reflected numerous assumptions concerning our anticipated future performance and with respect to prevailing and anticipated market and economic conditions that were and remain beyond our control and that may not materialize. Projections are inherently subject to substantial and numerous uncertainties and to a wide variety of significant business, economic and competitive risks and the assumptions underlying the projections and/or valuation estimates may prove to be wrong in material respects. Actual results will likely vary significantly from those contemplated by the projections. As a result, investors should not rely on these projections.

In addition, upon our emergence from bankruptcy, we adopted fresh start accounting. Accordingly, our future financial conditions and results of operations will not be comparable to the financial condition or results of operations reflected in the Company's historical financial statements. The lack of comparable historical financial information may discourage investors from purchasing our common stock.

There is a limited trading market for our securities and the market price of our securities is subject to volatility.

Upon our emergence from bankruptcy, our old common stock was cancelled and we issued new common stock. Our common stock is currently quoted on the OTCQX Market. The market price of our common stock could be subject to wide fluctuations in response to, and the level of trading that develops with our common stock may be affected by, numerous factors, many of which are beyond our control. These factors include, among other things, our new capital structure as a result of the transactions contemplated by the plan of reorganization, our limited trading history subsequent to our emergence from bankruptcy, our limited trading volume, the concentration of holdings of our common stock, the lack of comparable historical financial information due to our adoption of fresh start accounting, actual or anticipated variations in our operating results and cash flow, the nature and content of our earnings releases, announcements or events that impact our products, customers, competitors or markets, business conditions in our markets and the general state of the securities markets and the market for energy-related stocks, as well as general economic and market conditions and other factors that may affect our future results, including those described in this Part II, Item 1A of this Report. No assurance can be given that an active market will develop for the common stock or as to the liquidity of the trading market for the common stock. The common stock may be traded only infrequently in transactions arranged through brokers or otherwise, and reliable market quotations may not be available. Holders of our common stock may experience difficulty in reselling, or an inability to sell, their shares. In addition, if an active trading market does not develop or is not maintained, significant sales of our common stock, or the expectation of these sales, could materially and adversely affect the market price of our common stock.

The Company entered into an agreement with certain purchasers of our common stock in a recent private placement offering to list on a national securities exchange by July 25, 2017. However, no assurances can be given regarding the Company's ability to meet this deadline.

Upon our emergence from bankruptcy, the composition of our Board of Directors and our stockholders changed significantly.

Pursuant to the plan of reorganization, the composition of the Board and our stockholders changed significantly. The Board is now made up of six directors, none of whom served on the Board prior to emergence from bankruptcy. Our directors are also in large part nominated pursuant to a director nomination agreement among the Company and many of our large institutional stockholders that previously owned our unsecured high yield senior notes and received our common stock pursuant to the plan of reorganization. The new directors have different backgrounds, experiences and perspectives from those individuals who previously served on the Board and, thus, may have different views on the issues that will determine the future of the Company. As a result, the future strategy and plans of the Company may differ materially from those of the past.

There may be circumstances in which the interests of our significant stockholders could be in conflict with the interests of our other stockholders.

Funds associated with Strategic Value Partners LLC, ("SVP") and DW Partners, LP ("DW") currently own approximately 38.9% and 14.4%, respectively, of our outstanding common stock. SVP currently has a right to nominate two of our directors under our director nominating agreement. DW, together with other former noteholders who received our common stock pursuant to our plan of reorganization, collectively hold the current right to nominate two additional directors. Our current board is limited to seven directors under the terms of the director nomination agreement. Circumstances may arise in which these stockholders may have an interest in pursuing or preventing acquisitions, divestitures or other transactions, including the issuance of additional shares or debt, that, in their judgment, could enhance their investment in us or another company in which they invest. Such transactions might adversely affect us or other holders of our common stock. Furthermore, we have entered into a director nomination agreement with each of SVP, DW and other former holders of our senior notes that provides for certain continuing nomination rights subject to conditions on share ownership. In addition, our significant concentration of share ownership may adversely affect the trading price of our common shares because investors may perceive disadvantages in owning shares in companies with significant stockholders.

We do not expect to pay dividends in the near future.

We do not anticipate that cash dividends or other distributions will be paid with respect to our common stock in the foreseeable future. In addition, restrictive covenants in certain debt instruments to which we are, or may be, a party, may limit our ability to pay dividends or for us to receive dividends from our operating companies, any of which may negatively impact the trading price of our common stock.

A small number of institutional investors controls significant percentage of our voting power and possess negative control or veto rights with respect to certain proposed Company transactions

A small group of institutional investors, who are parties to our director nomination agreement currently, beneficially own a percentage majority of our issued and outstanding common stock. Consequently, such investors are able to strongly influence all matters that require approval by our stockholders, including the election and removal of directors, changes to our organizational documents and approval of acquisition offers and other significant corporate transactions. This concentration of ownership limits our other stockholders' ability to influence corporate matters. In addition, the institutional holders that are parties to the director nomination agreement possess negative control or veto rights under the Company's Certificate of Incorporation with respect to certain transactions the Company may propose to undertake for so long as such parties collectively hold 50% or more of the Company's issued and outstanding shares of common stock. Such parties are entitled to notice of certain proposed transactions which may be vetoed if such parties who collectively hold at least 50% of the issued and outstanding shares of common stock object to such action. These transactions the veto rights of the parties to the director nomination agreement include:

- the sale or other disposition of assets of the Company or any of its subsidiaries, in any single transaction or series of related transactions, with a fair market value in the aggregate in excess of $75 million, other than certain intercompany ordinary course transactions;
- any sale, recapitalization, liquidation, dissolution, winding up, bankruptcy event, reorganization, consolidation, or merger of the Company or any of its subsidiaries;

- issuing or repurchasing any shares of our common stock or other equity securities (or securities convertible into or exercisable for equity securities) in an amount that is in the aggregate in excess of $5 million, other than pursuant to employee benefit and incentive plans (including certain repurchases of capital stock to satisfy withholding or similar taxes in connection with any exercise of equity rights) and the issuance of shares of common stock upon exercise of our outstanding warrants;
- incurring any indebtedness for borrowed money (including through capital leases, the issuance of debt securities or the guarantee of indebtedness of another person or entity), in any single transaction or series of related transactions, that is in the aggregate in excess of $75 million other than indebtedness incurred to refinance indebtedness issued for less than $75 million, intercompany indebtedness, and certain other obligations incurred in the ordinary course of business;
- entering into any proposed transaction or series of related transactions involving a "Change of Control" of the Company (for purposes of this provision, "Change of Control" shall mean any transaction resulting in any person or group (as such terms are defined in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934) acquiring "beneficial ownership" (as defined in Rules 13d-3 and 13d-5 under the Securities Exchange Act of 1934) of more than 50% of the total outstanding equity interests of the Company (measured by voting power rather than number of shares);
- entering into or consummating any material acquisition of businesses, companies or assets (whether through sales or leases) or joint ventures, in any single transaction or series of related transactions, in the aggregate in excess of $75 million;
- increasing or decreasing the size of the Board;
- amending the Certificate of Incorporation or the Bylaws of the Company; or
- entering into any arrangements or transactions with affiliates of the Company.

Certain provisions of our certificate of incorporation and our bylaws may make it difficult for stockholders to change the composition of our Board and may discourage, delay or prevent a merger or acquisition that some stockholders may consider beneficial.

Certain provisions of our Certificate of Incorporation (the "Charter") and our Bylaws and our existing director nomination agreement may have the effect of delaying or preventing changes in control if our Board determines that such changes in control are not in the best interests of the Company and our stockholders. The provisions in our Charter and Bylaws and our existing director nomination agreement include, among other things, those that:

- provide for a classified board of directors;
- authorize our Board to issue preferred stock and to determine the price and other terms, including preferences and voting rights, of those shares without stockholder approval;
- establish advance notice procedures for nominating directors or presenting matters at stockholder meetings;
- provide SVP and certain other institutional stockholders the right to nominate up to four of our directors;
- limit the persons who may call special meetings of stockholders; and
- provide veto rights to certain stockholders as detailed in our Charter, including any transaction that may constitute a change of control, as defined in the Charter.

While these provisions have the effect of encouraging persons seeking to acquire control of the Company to negotiate with our Board, they could enable the Board to hinder or frustrate a transaction that some, or a majority, of the stockholders may believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors. These provisions may frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our Board, which is responsible for appointing the members of our management. Furthermore, we have entered into a director nomination agreement with each of SVP, DW and other former holders of our senior notes that provides for certain continuing nomination rights subject to conditions on share ownership.

The ability to attract and retain key personnel is critical to the success of our business and may be affected by our emergence from bankruptcy.

The success of our business depends on key personnel. The ability to attract and retain these key personnel may be difficult in light of our emergence from bankruptcy, the uncertainties currently facing the business and changes we may make to the organizational structure to adjust to changing circumstances. We may need to enter into retention or other arrangements that could be costly to maintain. If executives, managers or other key personnel resign, retire or are terminated, or their service is otherwise interrupted, we may not be able to replace them in a timely manner and we could experience significant declines in productivity.

Risks Related to the Business:

Oil and natural gas prices are volatile, and a substantial or extended decline in oil and natural gas prices would adversely affect our financial results and impede our growth.

Oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future. For example, oil and gas prices declined severely during 2015 with continued lower prices through 2016. The WTI crude oil price per barrel for the period from October 1, 2014 to December 31, 2016 ranged from a high of $91.02 to a low of $26.19, a decrease of 66.8%, and the NYMEX natural gas price per MMBtu for the period October 1, 2014 to December 31, 2016 ranged from a high of $4.41 to a low of $1.49, a decrease of 66.2%. As of December 31, 2016, the spot market price for WTI was $53.75 while the spot market price for natural gas was $3.71. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supplies of oil and natural gas;
- price and quantity of foreign imports of oil and natural gas;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil and natural gas price and production controls;
- level of consumer product demand, including as a result of competition from alternative energy sources;
- level of global oil and natural gas exploration and production activity;
- domestic and foreign governmental regulations;
- level of global oil and natural gas inventories;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America, Africa and Russia;
- weather conditions;
- technological advances affecting oil and natural gas production and consumption;
- overall U.S. and global economic conditions; and
- price and availability of alternative fuels.

Our financial condition, revenues, profitability and the carrying value of our properties depend upon the prevailing prices and demand for oil and natural gas. The speed and severity of the decline in oil prices during our 2015 fiscal year and the continued lower prices through 2016 has materially affected our results of operations and our estimates of our proved oil and natural gas reserves. Any sustained periods of low prices for oil and natural gas are likely to materially and adversely affect our financial position, the quantities of oil and natural gas reserves that we can economically produce, our cash flow available for capital expenditures and our ability to access funds through the capital markets, if they are available at all.

Insufficient capital 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. Our 2017 capital expenditure budget, including expenditures for leasehold acquisitions, drilling and infrastructure and fulfillment of abandonment obligations is expected to be in the range of $85.0 million and $95.0 million. Cash flow from operations is a principal source of our financing of our future capital expenditures. Insufficient cash flow from operations and inability to access capital could lead to losing leases that 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 reserves and production.

Most of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

We own leasehold interests in areas not currently held by production. Unless production in paying quantities is established or we exercise an extension option on units containing certain of these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. We have leases on 71,158 gross acres (66,575 net acres) that could potentially expire during fiscal year 2017, representing approximately 54% of our net undeveloped acreage.

Our drilling plans for areas not currently held by production are subject to change based upon various factors. Many of these factors are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On our acreage that we do not operate, we have less control over the timing of drilling; therefore there is additional risk of expirations occurring in those sections.

If low commodity prices continue for an extended period, our liquidity would be significantly reduced.

While substantially all of our $906 million of long-term unsecured indebtedness was discharged upon confirmation of our Plan, we will continue to have substantial capital needs following our emergence from bankruptcy, including in connection with our existing secured indebtedness and the continued development of our operations. As a result, we will need additional capital in the future to fund our operations, implement our business plan and fulfill our abandonment obligations. An extended period of low commodity prices would substantially reduce our cash flows and would likely reduce liquidity to a level that would make it increasingly difficult to operate our business.

We have written down the carrying values on our oil and gas properties in 2014, 2015 and 2016 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 period of April 23, 2016 through December 31, 2016 (successor), period of January 1, 2016 through April 22, 2016 (predecessor), the year ended December 31, 2015 (predecessor) and year ended December 31, 2014 (predecessor), we reported non-cash write-downs on a before-tax basis of, $133.5 million, $77.7 million, $1.6 billion ($1.5 billion after-tax) and $445.4 million ($287.3 million after-tax) respectively, on our oil and gas properties. If oil and natural gas prices decline in the future we could be required to record additional non-cash write-downs of our oil and gas properties. Refer to Note 2 of the consolidated financial statements in this Form 10-K for further discussion of the ceiling test calculation.

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 2016 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 and 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. These estimates may not accurately predict the present value of future net cash flows from our oil and natural gas reserves.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect the Company's production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. The Company is expected to use hydraulic fracturing techniques in certain of its operations. Hydraulic fracturing typically is regulated by state oil and gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in 2014, the U.S. Environmental Protection Agency ("EPA") asserted regulatory authority pursuant to the Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. The EPA also issued final federal Clean Air Act ("CAA") regulations in 2012 that include New Source Performance Standards ("NSPS") for completions of hydraulically fractured natural gas wells, compressors, controls, dehydrators, storage tanks, natural gas processing plants, and certain other equipment. In June 2016, the EPA published final rules establishing new emissions standards for methane and additional standards for volatile organic compounds ("VOCs") from certain new, modified and reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities, and is formally seeking additional information from oil and natural gas exploration and production operators as necessary to eventually expand these final rules to include existing equipment and processes. In addition, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants and, in 2014, published an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands but, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

The U.S. Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, certain states, including Texas, have adopted, and other states are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where the Company operates the Company could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. While this EPA report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, any future studies relating to hydraulic fracturing, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

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.

Our operations include the need of water for use in oil and natural gas exploration and production activities. The Company’s access to water may be limited due to reasons such as prolonged drought, private third party competition for water in localized areas, or the Company’s inability to acquire or maintain water sourcing permits or other rights. In addition, some state and local governmental authorities have begun to monitor or restrict the use of water subject to their jurisdiction for hydraulic fracturing to ensure adequate local water supply. Any such decrease in the availability of water could adversely affect the Company’s business and financial condition and operations. Moreover, any inability by the Company to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact the Company’s exploration and production operations and have a corresponding adverse effect on the Company’s business and financial condition.

Federal or state legislative and regulatory initiatives related to induced seismicity could result in operating restrictions or delays that could adversely affect the Company’s production of oil and natural gas.

Operations associated with our production and development activities generate drilling muds, produced waters and other waste streams, some of which may be disposed of by means of injection into underground wells situated in non-producing subsurface formations. These disposal wells are regulated pursuant to the UIC program established under the SDWA and analogous state laws. The UIC program requires permits from the EPA or an analogous state agency for construction and operation of such disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near underground disposal wells used for the disposal by injection of produced water or certain other oilfield fluids resulting from oil and natural gas activities. When caused by human activity, such events are called induced seismicity. Developing research suggests that the link between seismic activity and produced water disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or may have been, the likely cause of induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity: Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas.

In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for produced water disposal wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission adopted similar rules for the permitting of produced water disposal wells in 2014. These developments could result in additional regulation and restrictions on the use of injection wells in connection with Company activities to dispose of produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition, including litigation, to oil and natural gas activities utilizing injection wells for waste disposal. Any one or more of these developments may result in the Company having to limit disposal well volumes, disposal rates or locations, or require third party disposal well operators the Company may engage to dispose of produced water generated by Company activities to shut down disposal wells, which development could adversely affect the Company's production or result in the Company incurring increased costs and delays with respect to Company operations.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and gas the Company produces.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted regulations under the CAA that, among other things, establish certain permits and construction reviews designed to allow operations while ensuring the Prevention of Significant Deterioration of air quality by GHG emissions from large stationary sources that are already potential sources of significant, or criteria, pollutant emissions. The Company's operations could become subject to these permitting requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct in the future if they would otherwise emit large volumes of GHGs as well as criteria pollutants from such sources. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including onshore and offshore oil and gas production facilities, which may include certain Company operations. Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published NSPS, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and VOC emissions. These Subpart OOOOa standards will expand previously issued NSPS published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors and imposing leak detection and repair requirements for natural gas compressor and booster stations. Moreover, in November 2016, the EPA issued a final Information Collection Request seeking information about methane emissions from facilities and operations in the oil and natural gas industry. The EPA has indicated that it intends to use the information from this request to develop Existing Source Performance Standards for the oil and gas industry. Once adopted, these standards would not be imposed directly on regulated entities. Instead, they would become guidelines that the states must consider in developing their own rules for regulating sources within their borders. The EPA has indicated that this information may also be used to develop standards for certain kinds of new and modified equipment and facilities not currently covered under Subpart OOOOa. Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that proposed an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020 (the "Paris Agreement"). The Paris Agreement was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions.

The adoption and implementation of any international, federal or state legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from the Company's equipment and operations could require the Company to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax, which one or more developments could have an adverse effect on the Company's business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for, or lower the value of, the oil and gas the Company produces. Finally, it should be noted that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on the Company's operations. At this time, the Company has not developed a comprehensive plan to address the legal, economic, social, or physical impacts of climate change on the Company's operations.

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 natural gas leaks, oil spills, pipeline or tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- 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.

Pollution and property contamination arising from the Company's operations and the nearby operations of other oil and gas operators could expose the Company to significant costs and liabilities.

The performance of the Company's operations may result in significant environmental costs and liabilities as a result of handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater or other fluid discharges related to operations, and due to historical industry operations and waste disposal practices. Spills or other unauthorized releases of regulated substances by or resulting from the Company's operations, or the nearby operations of other oil and gas operators, could expose the Company to material losses, expenditures and liabilities under environmental laws and regulations. Certain of these laws may impose strict liability, which means that in some situations the Company could be exposed to liability as a result of the Company's conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior operators or other third parties. Neighboring landowners and other third parties may file claims against the Company for personal injury or property damage allegedly caused by the release of pollutants into the environment. Moreover, environmental laws and regulations generally have become more stringent in recent years and are expected to continue to do so, which could result in the occurrence of delays or cancellation in the permitting or performance of new or expanded projects, or more stringent or costly well drilling, construction, completion or water management activities or waste handling, storage, transport, disposal or cleanup requirements. Any one or more of such developments could require the Company to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on the oil and gas exploration and production industry in general in addition to the Company's own results of operations, competitive position or financial condition. The Company may not be able to recover some or any of its costs with respect to such developments from insurance.

Government regulation of the Company's activities could adversely affect the Company and its operations.

The oil and gas business is subject to extensive governmental regulation under which, among other things, rates of production from oil and gas wells may be regulated. Governmental regulation also may affect the market for the Company's production and operations. Costs of compliance with governmental regulation are significant, and the cost of compliance with new and emerging laws and regulations and the incurrence of associated liabilities could adversely affect the results of the Company. We cannot predict the timing or impact of new or changed laws, regulations, or permit requirements or changes in the ways that such laws, regulations, or permit requirements are enforced, interpreted or administered. For example, various governmental agencies, including the EPA and analogous state agencies, the BLM, and the Federal Energy Regulatory Commission can enact or change, begin to force compliance with, or otherwise modify their enforcement, interpretation or administration of, certain regulations that could adversely affect the Company.

The Company's operations are subject to environmental and worker safety and health laws and regulations that may expose the Company to significant costs and liabilities and could delay the pace or restrict the scope of the Company's operations.

The Company's oil and gas exploration, production and development operations are subject to stringent federal, regional, state and local laws and regulations governing worker safety and health, the release or disposal of materials into the environment or otherwise relating to environmental protection. Numerous governmental entities, including the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations, which may require the Company to take actions resulting in costly capital and operating expenditures at its wells and properties. These laws and regulations may restrict or affect the Company's business in many ways, including applying specific health and safety criteria addressing worker protection, requiring the acquisition of a permit before drilling or other regulated activities commence, restricting the types, quantities and concentration of substances that can be released into the environment, limiting or prohibiting construction or drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and imposing substantial liabilities for pollution resulting from the Company's operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigative, remedial or corrective action obligations, the occurrence of delays in the permitting or development or expansion of projects, and the issuance of orders enjoining performance of some or all of the Company's operations in a particular area.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and changes in environmental laws and regulations or re-interpretation of enforcement policies may result in increased costs and liabilities, delays or restrictions in the Company's operations. For example, during October 2015, the EPA issued a final rule lowering the National Ambient Air Quality Standard for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA is required to make attainment and non-attainment designations for specific geographic locations under the revised standards by October 1, 2017, and states may implement more stringent regulations, which could apply to the Company's operations. In a second example, in May of 2015, the EPA released a final rule outlining its position on federal jurisdiction over waters of the United States under the Federal Water Pollution Control Act. This interpretation by the EPA may constitute an expansion of federal jurisdiction over waters of the United States. The rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015 as that appellate court and several other courts considered lawsuits opposing implementation of the rule. Litigation surrounding this rule is on-going. Any expansion to the Federal Water Pollution Control Act jurisdiction in areas where Company's operations are conducted could, among other things, require installation of new emission controls on some of the Company's equipment, result in longer permitting timelines, and increase the Company's capital expenditures and operating costs, which could adversely impact the Company's business. In a third example, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its Resource Conservation and Recovery Act ("RCRA") Subtitle D criteria regulations for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the Company's costs to manage and dispose of wastes generated from its operations, which could effect on the Company's operations and financial position. The Company may be unable to pass on increased compliance costs arising out of its activities as a result of these developments to its customers.

Laws and regulations pertaining to threatened and endangered species or protective of environmentally sensitive areas could delay or restrict the Company's operations and cause it to incur substantial costs.

The Company's activities may be adversely affected by seasonal or permanent restrictions or costly mitigation measures imposed under various federal and state statutes in order to protect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. Federal statutes, as amended from time to time, that are protective of these species, birds and environmental sensitive areas include the Endangered Species Act ("ESA"), the Migratory Bird Treaty Act ("MBTA"), the Federal Water Pollution Control Act, the Comprehensive Environmental Response, Compensation and Liability Act of 1980, and the Oil Pollution Act of 1990. For example, to the extent that species are listed under the ESA or similar state laws, or are protected under the MBTA, live in the areas where the Company's activities are conducted, the Company's ability to conduct or expand operations and construct facilities could be limited or be forced to incur material additional costs. Moreover, the Company's activities may be delayed, restricted or precluded in protected habitat areas or during certain seasons, such as breeding and nesting seasons.

Additionally, the U.S. Fish and Wildlife Service ("FWS") may designate new or increased critical habitat areas that it believes are necessary for survival of threatened or endangered species, which designation could result in material restrictions to federal land use and private land use and could delay or prohibit land access or oil and natural gas development. Moreover, as a result of one or more settlements approved by the federal government, the FWS must make determinations on the listing of numerous specified species as endangered or threatened under the ESA under specific timelines. The designation of previously unidentified endangered or threatened species could indirectly cause the Company to incur additional costs, cause the Company's operations to become subject to operating restrictions or bans, and limit future development activity in affected areas. If harm to protected species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and natural gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or time delays or limitations on the Company's activities.

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

Numerous executive, legislative and regulatory proposals affecting the oil and gas industry have been introduced, are anticipated to be introduced, or are otherwise under consideration, by the President, Congress, state legislatures and various federal and state agencies. Among these proposals are: (1) proposed legislation (none of which has passed) to repeal various tax deductions available to oil and gas producers as discussed in more detail below and (2) the Pipeline Safety, Regulatory Certainty, and Job Creation Act enacted in 2011, which increases penalties, grants new authority to impose damage prevention and incident notification requirements, and directs the PHMSA to prescribe minimum safety standards for CO_2 pipelines.

The foregoing described proposals, including other applicable 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 the Company, its operations, the demand for oil and natural gas, or the 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 U.S. federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated as a result of future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and gas companies. Such legislative changes have included, but not been limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation, to accompany lower federal income tax rates. Moreover, other more general features of tax reform legislation, including changes to cost recovery rules and to the deductibility of interest expense, may be developed that also would change the taxation of oil and gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations and cash flows

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, environmental or contractual disputes, in the ordinary course of business. We defend ourselves vigorously in all such matters, if appropriate.

Because we maintain a portfolio of assets in the various areas in which we operate, the complexity and types of legal proceedings 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, damage to our properties and/or injuries. 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 are not aware of 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.
Bankruptcy Code - Refers to title 11 of the United States Code.
Bankruptcy Court - Refers to the United States Bankruptcy Court for the District of Delaware.
Bar Date - Refers to the deadline, set by the Bankruptcy Court, by which certain creditors must file proofs of claims in order to receive any distribution under the Plan.
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.
Chapter 11 - Means chapter 11 of the Bankruptcy Code.
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.
Effective Date - The Company's date of emergence from bankruptcy April 22, 2016.
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.
OTC Pink - means OTC Pink, a centralized electronic quotation service for over-the-counter securities, operated by OTC Market Group Inc.
Petition Date - The date on which the Company and the Chapter 11 Subsidiaries filed for bankruptcy protection (December 31, 2015).
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 1& 2. Business and 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

In the ordinary course of business, we are 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.

Item 4. Mine Safety Disclosures

Not Applicable.

PART II

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

Successor Common Stock, period of April 23, 2016 through December 31, 2016

Our common stock, is quoted on the OTCQX Market under the symbol "SWTF". The high and low quarterly closing sale prices for the common stock for the period of April 23, 2016 through December 31, 2016 (successor) were as follows:

	2016		
	Period from April 23, 2016 through June 30, 2016	Third Quarter	Fourth Quarter
Low	$22.00	$24.40	$26.77
High	$26.10	$31.00	$35.70

The high and low closing sale prices for the common stock reported on the OTCQX Market for the period of April 23, 2016 through December 31, 2016 (successor) were $22.00 and $35.70, respectively.

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 5 of the consolidated financial statements in this Form 10-K.

We had approximately 111 stockholders of record as of December 31, 2016.

Stock Repurchase Table

The following table summarizes repurchases of our common stock during the fourth quarter of 2016, 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, 2016	15,249	$ 30.50	—	$---
November 1- 30, 2016	7,236	$ 29.00	—	—
December 1 - 31, 2016	—	$ —	—	—
Total	22,485	$ 30.02	—	$---

Equity Compensation Plan Information

For 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, 2016 see Note 8 of the consolidated financial statements included in this Form 10-K.

Item 6. Selected Financial Data

(data in thousands except per share, price and well amounts)	Successor	Predecessor				
	April 23, 2016 - December 31, 2016	January 1, 2016 - April 22, 2016	Years Ended December 31,			
			2015	2014	2013	2012
Total Revenues	$ 101,537	$ 42,782	$ 244,721	$ 549,456	$ 584,401	$ 561,486
Income (Loss) Before Income Taxes	$ (156,288)	$ 851,611	$ (1,734,514)	$ (433,470)	$ 198	$ 37,773
Net Income (Loss)	$ (156,288)	$ 851,611	$ (1,653,971)	$ (283,427)	$ (2,442)	$ 21,701
Net Cash Provided by Operating Activities	$ 47,427	$ (41,466)	$ 42,274	$ 306,371	$ 311,447	$ 314,606
Per Share and Share Data						
Weighted Average Shares Outstanding - Basic	10,013	44,692	44,463	43,795	43,331	42,840
Earnings per Share - Basic	$ (15.61)	$ 19.06	$ (37.20)	$ (6.47)	$ (0.06)	$ 0.51
Earnings per Share - Diluted	$ (15.61)	$ 18.64	$ (37.20)	$ (6.47)	$ (0.06)	$ 0.50
Production (MMBoe equivalent)	6.4	2.8	11.1	11.6	11.4	11.4
Average Sales Price (1)						
Natural Gas (per Mcf produced)	$ 2.55	$ 1.96	$ 2.56	$ 4.36	$ 3.66	$ 2.64
Natural Gas Liquids (per barrel)	$ 16.39	$ 11.04	$ 14.54	$ 31.83	$ 31.39	$ 35.07
Oil (per barrel)	$ 44.79	$ 31.43	$ 47.11	$ 92.74	$ 103.42	$ 106.17
Boe Equivalent	$ 19.07	$ 15.33	$ 22.09	$ 47.20	$ 52.29	$ 49.42

(1) These prices do not include the effects of our hedging activities which were recorded in "Price-risk management and other, net" on the consolidated statements of operations included in this Form 10-K.

Balance Sheet Data	Successor	Predecessor			
	December 31, 2016	December 31, 2015	2014	2013	2012
Assets					
Current Assets	$ 21,479	$ 61,847	$ 64,669	$ 92,489	$ 87,005
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	347,195	457,903	2,095,037	2,588,817	2,367,954
Total Assets	377,299	524,998	2,173,347	2,698,505	2,473,463
Liabilities					
Current Liabilities [(1)]	79,124	333,053	148,919	176,033	179,412
Long-Term Debt [(1)]	198,000	—	1,074,534	1,142,368	916,934
Total Liabilities	301,244	1,377,722	1,378,969	1,633,155	1,420,680
Stockholders' Equity (Deficit)	$ 76,055	$ (852,724)	$ 794,378	$ 1,065,350	$ 1,052,783
Shares Outstanding at Year-End	10,054	44,592	43,918	43,402	42,930
Book Value per Share at Year-End	$ 7.56	$ (19.12)	$ 18.09	$ 24.55	$ 24.52
Additional Information					
Producing Wells					
Swift Operated	$ 774	$ 1,030	$ 1,040	$ 1,039	$ 1,069
Outside Operated	$ 5	$ 26	$ 25	$ 25	$ 50
Total Producing Wells	$ 779	$ 1,056	$ 1,065	$ 1,064	$ 1,119
Wells Drilled (Gross)	$ 7	$ 24	$ 36	$ 48	$ 71
Proved Reserves					
Natural Gas (Bcf) [(2)]	$ 626.8	$ 311.7	$ 686.7	$ 815.1	$ 597.6
Oil Reserves (MBoe) [(2)]	$ 5.8	$ 10.1	$ 49.7	$ 53.0	$ 43.3
NGL Reserves (MBoe) [(2)]	$ 13.7	$ 8.2	$ 29.7	$ 30.4	$ 49.2
Total Proved Reserves (MMBoe equivalent)	$ 124.0	$ 70.3	$ 193.8	$ 219.2	$ 192.1

(1) Reduction in Long-Term Debt is due to reclassifications of (a) the Company's Senior Notes to Liabilities Subject to Compromise and (b) borrowings under the credit facility to Current Liabilities in 2015, both as a result of the bankruptcy filing.

(2) Reserves decreased during 2015 due to the impact of lower commodity prices and uncertainties, due in part to our bankruptcy filing, surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves.

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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor) included in this Form 10-K. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 46 of this report.

As discussed in Notes 1A and 1B to the consolidated financial statements included herein, the Company applied fresh start accounting upon emergence from bankruptcy on April 22, 2016, at which time it became a new entity for financial reporting purposes. The effects of the Plan of Reorganization (described below) and the application of fresh start accounting were reflected in our consolidated financial statements as of April 22, 2016 and the related adjustments thereto were recorded in our consolidated statements of operations as reorganization items for the period April 1, 2016 to April 22, 2016 (predecessor). References to the Successor relate to the Company on and subsequent to the Effective Date. References to Predecessor refer to the Company prior to the Effective Date.

Company Overview

We are an independent oil and natural gas company 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. We hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development. Natural gas production accounted for 76% of our production and 61% of our oil and gas sales, while oil accounted for 12% of our production and 29% of our oil and gas sales for the reporting period of April 23, 2016 through December 31, 2016 (successor). Combined production of both oil and natural gas constituted 88% of our production and 90% of our oil and gas sales for the reporting period of April 23, 2016 through December 31, 2016 (successor).

Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On December 31, 2015, we and the Chapter 11 Subsidiaries filed voluntary petitions seeking relief under Chapter 11 of Title 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware under the caption *In re Swift Energy Company, et al* (Case No. 15-12670). The Company and the Chapter 11 Subsidiaries received bankruptcy court confirmation of their joint plan of reorganization (the "Plan") on March 31, 2016, and subsequently emerged from bankruptcy on April 22, 2016.

Effect of the Bankruptcy Proceedings. During the bankruptcy proceedings, the Company conducted normal business activities and was authorized to pay and has paid (subject to caps applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders and critical vendors, pre-petition amounts owed to pipeline owners that transport the Company's production, and funds belonging to third parties, including royalty holders and partners.

In addition, subject to certain specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. As a result, we did not record interest expense on the Company's senior notes for the period of January 1, 2016 through April 22, 2016 (as the predecessor). For that period, contractual interest on the senior notes totaled $21.6 million.

Plan of Reorganization. Pursuant to the Plan, the significant transactions that occurred upon emergence from bankruptcy were as follows:

- the approximately $906 million of indebtedness outstanding on account of the Company's senior notes, the $75 million drawn under the Company's DIP Credit Agreement (described below) and certain other unsecured claims were exchanged for 88.5% of the post-emergence Company's common stock;
- the lenders under the DIP Credit Agreement (as defined and more fully described below) received a backstop fee consisting of 7.5% of the post-emergence Company's common stock which was not included in the 88.5% distributed to creditors;
- the Company's pre-petition common stock was canceled and the previous shareholders received 4% of the post-emergence Company's common stock and warrants to purchase up to 30% of the reorganized Company's equity;
- the warrants (each for up to 15% of the reorganized Company's equity), are exercisable at prices that represent a substantial increase from the value at emergence, as follows:

Issue Date	Expiration Date	Shares	Strike Price
April 22, 2016	April 22, 2019	2,142,857	$80.00
April 22, 2016	April 22, 2020	2,142,857	$86.18

- claims of other creditors were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditors;
- the Company entered into a registration rights agreement to provide customary registration rights to certain holders of the Company's post-emergence common stock who, together with their affiliates received upon emergence 5% or more of the outstanding common stock of the Company;
- the Company sold (effective April 15, 2016) a portion of its interest in its Central Louisiana fields known as Burr Ferry and South Bearhead Creek to Texegy LLC, for net proceeds of approximately $46.9 million including deposits received prior to the closing date; and
- the Company's previous credit facility (the "Prior First Lien Credit Facility") was terminated and a new senior secured credit facility (the "New Credit Facility") with an initial $320 million borrowing base was established. For more information refer to Note 5 of the accompanying consolidated financial statements in this Form 10-K.

In accordance with the Plan, the post-emergence Company's new board of directors was initially to be made up of seven directors consisting of the Chief Executive Officer, two directors appointed by Strategic Value Partners LLC ("SVP"), a former holder of the Company's senior notes, two directors appointed by other former holders of the Company's senior notes, one independent director and one independent non-executive chairman of the Board. In addition, pursuant to the Plan, SVP and the other former holders of the Company's senior notes were given certain continuing director nomination rights subject to minimum share ownership conditions.

DIP Credit Agreement. During the bankruptcy, we had a debtor-in-possession credit facility (the "DIP Credit Agreement") that provided for a multi-draw term loan of up to $75 million, which became available to the Company upon the satisfaction of certain milestones and contingencies. Upon emergence from bankruptcy, the Company had drawn down the entire $75 million available. Pursuant to the Plan, the borrowings under the DIP Credit Agreement, at the option of the lenders to the DIP Credit Agreement, converted into the post-emergence Company's common stock, which was part of the 88.5% of the common stock distributed to the holders of the Company's senior notes and certain unsecured creditors. As such, the $75 million borrowed under the DIP Credit Agreement was not required to be repaid in cash and terminated upon the Company's emergence from bankruptcy. For more information refer to Note 5 the accompanying consolidated financial statements in this Form 10-K.

Fresh Start Accounting. Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh start accounting in accordance with the provisions of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 852, "*Reorganizations*" which resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. The Effective Date fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our historical consolidated balance sheet. The effects of the Plan and the application of fresh start accounting were reflected in our consolidated financial statements as of April 22, 2016 and the related adjustments thereto were recorded in our consolidated statements of operations as reorganization items for the period April 1, 2016 to April 22, 2016 (predecessor).

As a result, our consolidated balance sheets and consolidated statement of operations subsequent to the Effective Date are not comparable to our consolidated balance sheets and statements of operations prior to the Effective Date. Our consolidated financial statements and related footnotes are presented with a black line division which delineates the lack of comparability between amounts presented after April 22, 2016 and dates on or prior to April 22, 2016. Our financial results for future periods following the application of fresh start accounting will be different from historical trends and the differences may be material.

Financial Statement Classification of Liabilities Subject to Compromise. Our financial statements included amounts classified as liabilities subject to compromise, a majority of which were equitized upon emergence from bankruptcy on April 22, 2016. See Note 1B of the accompanying consolidated financial statements in this Form 10-K for more information.

Significant Developments during 2016

- *Management Changes:* On October 7, 2016, the Company announced that Robert J. Banks (current Chief Operating Officer) would serve as interim Chief Executive Officer of the Company, filling the position vacated by the retirement of Terry E. Swift on the same date. Furthermore, on August 9, 2016 the Company announced the Chief Financial Officer of the Company would also be retiring but would serve in the same capacity until a replacement is named. The Company is actively engaged in finding full time replacements for both of these key positions. On September 27, 2016, the Company announced the appointment of Marcus C. Rowland as the non-executive Chairman of the Board, a position that was previously filled on an interim basis by another member of the Board since the Company's emergence from its Chapter 11 restructuring.

- *Weak crude oil and natural gas prices continue to affect our business:* Oil and gas prices declined during 2015 and continue to remain relatively low by historical measures. While we are negatively impacted by weak commodity prices, the resulting industry downturn has created a much more competitive environment among oil field service companies, providing an opportunity for us to bring our cost structure in line with lower revenues. The recent rebound of oil and gas prices from their 2016 lows has allowed the Company to enter into price and basis differential hedges for calendar year 2017 production and the first quarter of 2018 production, which could partially mitigate future commodity price weakness.

- *Operational activity:* At our Fasken field in the Eagle Ford play, eight wells were completed and placed into the system in early 2016. Seven wells were placed into the system at rates between 15 - 20 MMcf per day of natural gas and one well had mechanical issues and was placed into the system at a restricted rate of 9 MMcf per day of natural gas. The Company resumed drilling operations at Fasken in October 2016 and drilled eight more wells by the end of the year.

- *2016 changes in reserve quantities and value:* Our 76%, or 54 MMBoe, increase in proved reserves quantities from 2015 to 2016 was principally due to additions of undeveloped reserves which were previously not included in 2015 because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing.

- *2016 cost reduction initiatives:* We are continuing the cost reduction efforts initiated in 2015, and have taken additional actions during 2016 to significantly reduce our operating and overhead costs. In conjunction with our reorganization through Chapter 11 bankruptcy, we have renegotiated a number of contracts with vendors and service providers to bring costs in line with current market conditions. Other initiatives include field staff reductions, intermittent production of marginal properties, disposition of uneconomic and higher cost properties, full utilization of existing facilities and elimination of redundant equipment. At the corporate level we have also undergone significant staff reductions, reduced the square footage of leased office space and are taking additional steps to further reduce overhead costs.

- *Strategic dispositions:* Effective December 1, 2016, we closed our transaction with Hilcorp Energy I, L.P. for the sale of the Company's holdings in our Lake Washington field located in Southeast Louisiana. We received net proceeds of approximately $37.0 million which were used to reduce the amount of borrowings under the Company's credit facility. The buyer assumed approximately $30.5 million of plugging and abandonment liability. No gain or loss was recorded on the sale of the property. In addition, on December 8, 2016 we sold the remaining 25% working interest share of the Company's holdings in the South Bearhead Creek and Burr Ferry fields. We received net proceeds of $7.1 million on the sale which were used to reduce the amount of borrowings under the Company's credit facility.

- *Stock listing:* Trading in the Company's former common stock on the NYSE was suspended on December 18, 2015, and the common stock was subsequently delisted from the NYSE. The common stock of the Company traded on the OTC Pink marketplace under the symbol "SFYWQ" until the former common stock was canceled on April 22, 2016, pursuant to the plan of reorganization confirmed by the bankruptcy court. On October 3, 2016, the Company announced the common stock of the Company issued pursuant to the plan of reorganization was approved for quoting on the OTCQX Market. The Company is traded under the ticker "SWTF". Effective January 25, 2017 , the Company entered into an agreement with certain purchasers of our common stock in a recent private placement offering to list on a national securities exchange by July 25, 2017.

Summary of 2016 Financial Results

- *2016 revenues and net loss:* The Company's oil and gas revenues were $43.0 million and $121.4 million in the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively. Full year 2015 revenues were $246.3 million. Revenues were lower primarily due to lower oil and natural gas pricing as well as overall lower production. The Company's net income of $851.6 million in the period of January 1, 2016 through April 22, 2016 (predecessor) was primarily due to the gain on reorganization adjustments as part of our emergence from bankruptcy while the net loss of $156.3 million in the period of April 23, 2016 through December 31, 2016 (successor) was primarily due to the $133.5 million non-cash write-down of our oil and gas properties and losses on derivative instruments of $19.7 million.

- *2016 capital expenditures:* The Company maintained a limited capital budget for 2016 with a focus on balancing capital expenditures with cash flows. The Company's capital expenditures on a cash basis were $24.5 million and $45.7 million in the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively. The expenditures for the period January 1, 2016 through April 22, 2016, were primarily devoted to completion of wells in South Texas that were drilled in 2015. These expenditures were funded by cash flows and borrowings under our DIP credit facility. Capital expenditures since April 23, 2016 were focused on drilling and completion activities in our Fasken field. These expenditures were primarily funded by operating cash flows and proceeds from property dispositions.

- *Working capital:* Working capital, as measured by current assets less current liabilities, is one of several measures the Company uses to track its short-term liquidity position. The Company had a working capital deficit of $57.6 million at December 31, 2016 and a deficit of $271.2 million at December 31, 2015, excluding any available borrowings under the Company's credit facility. These numbers are not comparable given the Company's bankruptcy filing on December 31, 2015. For example, the deficit at December 31, 2015 included the Company's Prior First Lien Credit Facility borrowings as a current liability while other current payables were reclassified as Liabilities Subject to Compromise, which were excluded from new working capital computation. For covenant purposes, the working capital computation includes available borrowings under the credit facility. For more information on our Current Ratio covenant see Note 5 of the accompanying consolidated financial statements in this Form 10-K.

- *Cash Flows:* For the period of April 23, 2016 through December 31, 2016 (successor) the Company generated cash from Operating Activities of $47.4 million, of which $8.2 million was attributable to changes in working capital. Additionally we realized $46.0 million in net proceeds from asset sales during this period. Cash used for property additions was $45.7 million. This included $6.3 million attributable to net pay-down of capital related payables and accrued cost as the Company paid a significant portion of the well completion costs from earlier in the year during this period. The Company’s net payments on its line of credit were $55.0 million for this period.

  For the period of January 1, 2016 through April 22, 2016 (predecessor) (which included the impact of cash transactions occurring upon emergence from bankruptcy) the Company’s operating cash flow deficit was $41.5 million, of which $16.3 million was attributable to working capital changes. During this period the Company incurred $25.6 million in legal and professional fees related to its bankruptcy and reorganization activities. While the Company paid $24.5 million for capital expenditures, it realized $48.7 million from asset sales (primarily from the sales of properties in Central Louisiana) and received $75 million in proceeds from its DIP credit facility. It utilized $71.9 million to pay down its bank credit facility from $324.9 million to $253.0 million prior to emergence from bankruptcy. The remaining $253.0 million was refinanced with the Company’s new credit facility. The Company also paid $10.4 million for interest during the period and $6.5 million for debt issuance costs associated with obtaining the new credit facility.

  For the year ended December 31, 2015 the Company generated $42.3 million from operating activities but paid out $139.7 million for capital expenditures, including a net pay down of $27.6 million in payables and accrued capital for 2014 activity. The Company drew a net $127.6 million on its bank credit facility during the period.

Summary of Operational Achievements during 2016

- *Reductions in per well costs:* We have seen significant improvements in drilling costs and drilling days for our Fasken wells in the fourth quarter of 2016 with average drilling costs per well decreasing to $1.8 million from $2.4 million during 2015 and drilling days per well decreasing from 20 days to 11 days over the same period. We have also significantly lowered the frac and completion costs of the Fasken wells. Our fourth quarter average completion costs per well are $2.3 million compared to an average completion cost of $3.2 million for the first two quarters of 2016.

- *Reductions in operating costs:* In addition to the initiatives summarized above, during 2016 we implemented a number of operational initiatives to reduce lease operating expenses. This included a reconfiguration of the gathering system in Lake Washington to consolidate production into one platform. This effort significantly reduced operating expenses in this field which we believe enhanced the value we realized from the disposition. For 2017 in our South Texas area, we are continuing to implement additional operating cost reduction initiatives including a reduction in headcount, eliminating redundant equipment, and shutting in or divesting wells with marginal production or high operating costs.

2016 Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operations, borrowings under our Prior First Lien Credit Agreement and issuances of senior notes. Our primary use of cash flow has been to fund capital expenditures used to develop our oil and gas properties. Upon emergence from bankruptcy, our primary sources of liquidity were cash flows from operations, proceeds from asset sales and borrowings under the New Credit Facility. As of December 31, 2016, the Company’s liquidity consisted of approximately \$0.3 million of cash-on-hand and \$106.9 million in available borrowings (calculated as \$122 million of borrowing availability less \$5.1 million in letters of credit and a \$10 million minimum liquidly requirement) on the \$320 million borrowing base. Effective January 26, 2017, the Company and the lenders agreed to terminate the non-conforming borrowing base leaving only the conforming borrowing base of \$250 million available.

Disposition of Assets. On April 15, 2016, we closed our transaction with Texegy LLC for the sale of a 75% working interest share of the Company's holdings in the South Bearhead Creek and Burr Ferry field areas located in Central Louisiana. The net proceeds were \$46.9 million for this transaction, including deposits received prior to the closing date. These proceeds were used primarily to reduce the amount of borrowings under the Company’s Prior First Lien Credit Facility, and for other general corporate purposes. This disposition also included the buyer's assumption of approximately \$6.5 million of plugging and abandonment liability. On December 8, 2016 we sold the remaining 25% working interest share of the Company's holdings in our South Bearhead Creek and Burr Ferry fields to Texegy. We received net proceeds of \$7.1 million on the sale which were used to reduce the amount of borrowings under the Company's credit facility. This disposition also included the buyer's assumption of approximately \$2.4 million of plugging and abandonment liability.

Effective April 25, 2016, we disposed of our Masters Creek field in Central Louisiana. We received net proceeds of less than \$0.1 million and the buyer assumed approximately \$8.1 million of plugging and abandonment liability.

Effective September 30, 2016, we closed our transaction with Blue Marble Resources LLC for the sale of the Company's holdings in our Sun TSH field located in South Texas. We received net proceeds of approximately \$0.9 million and the buyer assumed approximately \$1.8 million of plugging and abandonment liability.

On December 1, 2016, we closed our transaction with Hilcorp Energy I, L.P., effective September 1, 2016, for the sale of the Company's holdings in our Lake Washington field located in South East Louisiana. We received net proceeds of approximately \$37.0 million which were used to reduce the amount of borrowings under the Company's credit facility. The buyer assumed approximately \$30.5 million of plugging and abandonment liability.

Effective December 16, 2016, we sold an overriding royalty package in the Barnett Shale area for \$0.5 million to San Saba Royalty Company.

In accordance with our Full Cost Accounting policy no gains or losses were recognized on these disposition transactions. The sales proceeds were credited to our proved oil and gas property accounts.

New Credit Facility and Prior First Lien Credit Agreement. Upon our emergence from bankruptcy, the Prior First Lien Credit Agreement was terminated and paid in full, and the Company entered into the New Credit Facility among the Company, as borrower, JPMorgan Chase Bank, National Association, as administrative agent, and certain lenders party thereto. The New Credit Facility matures in 2019 and provides for advancing loans of up to the maximum credit amount that the lenders, in the aggregate, make available, subject to the Company meeting certain financial requirements, including certain financial tests. As of our emergence from bankruptcy, the maximum credit amount was \$500 million with an initial borrowing base of \$320 million. The obligations under the New Credit Facility are secured, subject to certain exceptions, by a first priority lien on substantially all assets of the Company and certain of its subsidiaries including a first priority lien on properties attributed with at least 95% of estimated proved producing reserves of the Company and its subsidiaries. This borrowing base was affirmed in our first semi-annual borrowing base redetermination in November 2016. As of December 31, 2016, we had \$198 million in outstanding borrowings under the New Credit Facility. The terms of the New Credit Facility included the following, based on terms as defined in the New Credit Facility agreement:

- The initial borrowing base was initially allocated between a non-conforming borrowing base of \$70 million, which was scheduled to terminate on November 1, 2017, and a conforming borrowing base of \$250 million. Effective January 26, 2017, the Company and the lenders agreed to terminate the non-conforming borrowing base leaving only the conforming borrowing base of \$250 million.
- Borrowing base redeterminations are scheduled to occur semi-annually in November and May and are determined by the lenders at their discretion and in the usual and customary manner.

- The interest rate for Alternative Base Rate ("ABR") loans will be based on the ABR plus the applicable margin and the interest rate for Eurodollar loans will be based on the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin.
- As of December 31, 2016, the applicable margins varied and had escalating rates of either (a) 500 to 600 basis points for ABR loans and 600 to 700 basis points for Eurodollar loans, during the non-conforming period, and depending on the level of the non-conforming borrowing base and the non-conforming borrowing base loans outstanding, or (b) 200 to 300 basis points for ABR loans and 300 to 400 basis points for Eurodollar loans depending on the borrowing base utilization percentage, after the non-conforming period or when both the non-conforming borrowing base is zero. Given the termination of the non-conforming borrowing base effective January 26, 2017, the applicable margins going forward are 200 to 300 basis points for ABR loans and 300 to 400 basis points for Eurodollar loans, significantly reducing our future interest expense. As of December 31, 2016, our average borrowing rate was 7.9%.
- Certain covenants, including (a) a ratio of total debt to EBITDA as defined in the agreement not to exceed 6 to 1 for the quarter ending December 31, 2016, declining gradually over time to 3.5 to 1.0 for the quarter ending March 31, 2019, and thereafter, (b) a current ratio of not less than 1.0 to 1.0, which includes the unused portion of our borrowing base, and (c) a minimum liquidity requirement of $10 million. As of December 31, 2016, the Company was in compliance with these covenants and liquidity requirements.

We expect to be in compliance with the covenants under this agreement during the next twelve months from the date of filing of this Form 10-K. Maintaining or increasing borrowing base under our New Credit Facility is dependent upon many factors, including commodities pricing, our hedge positions and our ability to raise capital to drill wells to replace produced reserves.

2017 Private Placement of Common Stock. Effective January 25, 2017 the Company entered into an agreement to sell approximately 1.4 million shares of its Common Stock in a private placement at a price of $28.50 per share, which resulted in approximately $40.0 million in gross proceeds. The shares were sold to select institutional accredited investors and proceeds were primarily used to repay credit facility borrowings. The securities offered in the private placement have not been registered under the Securities Act of 1933 or any state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements of the Securities Act and applicable state laws.

2017 Capital Spending. The Company's net operational capital budget for 2017 is expected to be in the range of $85.0 million and $95.0 million. The Company plans to drill and complete 12 wells in the first half of 2017. Specifically, the Company expects to complete nine wells (not including 3 wells drilled and completed in late 2016) in its Fasken field in Webb County, drill and complete 2 wells on its AWP acreage in McMullen County, and drill and complete its first well in Oro Grande in LaSalle County. All drilling activities will target the Eagle Ford formation. The Company expects to spud the Oro Grande appraisal well in the second quarter of 2017. The anticipated capital budget is inclusive of the aforementioned completions as well as associated drilling activities, infrastructure, abandonment activities and other discretionary expenditures.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter are shown below as of December 31, 2016 (in thousands):

	2017	2018	2019	2020	2021	Thereafter	Total
Non-cancelable operating leases (1)	$ 5,460	$ 2,016	$ 621	$ 487	$ 204	$ —	$ 8,788
Asset retirement obligation (2)	9,965	5,224	4,549	4,953	66	7,499	32,256
Drilling, Completion and Geoscience Contracts	1,320	—	—	—	—	—	1,320
Gas transportation and Processing (3)	8,254	13,542	12,782	10,846	—	—	45,424
Interest Cost (4)	8,415	7,920	2,462	—	—	—	18,797
Credit facility	—	—	198,000	—	—	—	198,000
Executive severance agreements	2,464	786	—	—	—	—	3,250
Total	$ 35,878	$ 29,488	$ 218,415	$ 16,286	$ 271	$ 7,499	$ 307,835

(1) We signed a new sub-lease on our corporate headquarters commencing on January 1, 2017. For additional discussion regarding the terms and obligations of this lease refer to Note 7 of the consolidated financial statements in this Form 10-K.
(2) Amounts shown by year are the net present value at December 31, 2016. Approximately 81% of the 2017 through 2021 obligation is for the Bay de Chene Field in Louisiana
(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) Interest is estimated using 4% APR after credit facility amendment, see Note 5 of these consolidated financial statements in this Form 10-K. Actual interest rate is variable over the term of the facility.

As of December 31, 2016, we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Proved Oil and Gas Reserves

During 2016, our reserves increased by approximately 54 MMBoe due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing, partially offset by the sale of our Louisiana and other properties. As of December 31, 2016, 51% of our total proved reserves were proved developed, compared with 80% at year-end 2015 and 34% at year-end 2014.

At December 31, 2016, our proved reserves were 124.0 MMBoe with a Standardized Measure of $407 million, which is an increase of approximately $33 million, or 9%, from the prior year-end levels. In 2016, our proved natural gas reserves increased 315.1 Bcf, or 101%, while our proved oil reserves decreased 4.3 MMBbl, or 43%, and our NGL reserves increased 5.5 MMBbl, or 67%, for a total equivalent increase of 54 MMBoe, or 76%.

In prior years we have added proved reserves primarily through our drilling activities, including 18.2 MMBoe added in 2014. We obtained reasonable certainty regarding these reserve additions by applying the same methodologies that have been used historically in this area. We also sold approximately 7.1 MMBoe of reserves during 2016 in conjunction with our dispositions, as described further in Note 10 of our consolidated financial statements in this Form 10-K.

We use the preceding 12-month's 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 Standardized Measure calculation. Our average natural gas price used in the Standardized Measure calculation for 2016 was $2.43 per Mcf. This average price decreased from the average price of $2.61 per Mcf used for 2015. Our average oil price used in the calculation for 2016 was $41.07 per Bbl. This average price decreased from the average price of $49.58 per Bbl used in the calculation for 2015.

Results of Operations

Revenues — Period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor)

The tables included below set forth financial information for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor) which are distinct reporting periods as a result of our emergence from bankruptcy on April 22, 2016.

Certain reclassifications have been made to 2015 and 2014 sales volumes from previously reported volumes to conform to the current-year presentation. Previously disclosed production volumes included natural gas consumed in operations. All current and prior year production is now shown based on volumes sold rather than volumes produced.

2016 - Our oil and gas sales in 2016 decreased by 33% compared to revenues in 2015, primarily due to lower oil and natural gas prices and overall lower production volumes. Average oil prices we received were 16% lower than those received during 2015, while natural gas prices were 7% lower, and NGL prices were flat.

2015 - Our oil and gas sales in 2015 decreased by 55% compared to revenues in 2014, due to the impact of overall lower commodity prices and lower oil and NGL volumes, partially offset by higher natural gas production. Average oil prices we received were 49% lower than those received during 2014, while natural gas prices were 41% higher, and NGL prices were 54% higher.

Crude oil production was 12%, 19%, 22% and 30% of our production volumes while crude oil sales revenues were 29%, 38%, 46% and 59% of oil and gas sales revenue for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor), the year ended December 31, 2015 (predecessor) and the year ended December 31, 2014 (predecessor), respectively. Natural gas production was 76%, 68%, 66% and 54% of our production volumes while natural gas sales revenues were 61%, 52%, 46% and 30% of oil and gas sales for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor), the year ended December 31, 2015 (predecessor) and the year ended December 31, 2014 (predecessor), respectively.

The following tables provide information regarding the changes in the sources of our oil and gas sales and volumes for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor):

Fields	Oil and Gas Sales (In Millions)			
	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Artesia Wells	$ 9.9	$ 3.5	$ 19.3	$ 62.2
AWP	42.4	14.7	87.1	224.8
Fasken	53.0	14.3	72.1	87.2
Other (1)	16.1	10.5	67.8	173.6
Total	$ 121.4	$ 43.0	$ 246.3	$ 547.8

(1) Primarily fields sold during 2016 including our former Lake Washington, South Bearhead Creek and Burr Ferry fields.

Fields	Net Oil and Gas Production Volumes (MBoe)				
	Successor	Predecessor			
	(a)	(b)	(a) + (b)		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Artesia Wells	484	257	741	1,048	1,627
AWP	1,980	951	2,931	3,618	4,299
Fasken	3,462	1,213	4,675	4,769	3,516
Other (1)	439	386	825	1,711	2,162
Total	6,365	2,807	9,172	11,146	11,604

(1) Primarily fields sold during 2016 including our former Lake Washington, South Bearhead Creek and Burr Ferry fields.

Our production decrease from 2015 to 2016 was primarily due overall decreased production due to natural declines, reduced drilling and completion activity and strategic dispositions of our non-core fields during the year.

In 2016, our $81.9 million, or 33% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $17.0 million unfavorable impact on sales, with a decrease of $10.0 million due to the 16% decrease in oil prices received and a decrease of $7.0 million due to the 7% decrease in natural gas prices.
- Volume variances that had a $64.9 million unfavorable impact on sales, with a $51.7 million decrease due to the 1.1 million Bbl decrease in oil production volumes, an $8.4 million decrease due to the 3.3 Bcf decrease in natural gas production volumes and a $4.7 million decrease due to the 0.3 million Bbl decrease in NGL production volumes.

In 2015, our $301.5 million, or 55% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $206.2 million unfavorable impact on sales, with a decrease of $109.8 million due to the 49% decrease in oil prices received, a decrease of $71.6 million due to the 39% decrease in natural gas prices and a decrease of $24.8 million due to the 54% decrease in NGL prices.
- Volume variances that had a $95.4 million unfavorable impact on sales, with a $102.4 million decrease due to the 1.1 million Bbl decrease in oil production volumes and a $12.1 million decrease due to the 0.4 million Bbl decrease in NGL production volumes, partially offset by a $19.2 million increase due to the 4.9 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the period of January 1, 2016 through April 22, 2016 (predecessor), the period of April 23, 2016 through December 31, 2016 (successor), and for the years ended December 2015 and 2014 (predecessor):

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2014 (Predecessor)							
First Quarter	931	478	8.7	2,853	$99.38	$36.27	$4.46
Second Quarter	890	434	12.1	3,344	$101.67	$33.93	$4.37
Third Quarter	870	482	7.3	2,565	$96.12	$33.39	$4.81
Fourth Quarter	820	418	9.6	2,842	$71.94	$22.74	$3.93
Total	3,511	1,812	37.7	11,604	$92.74	$31.83	$4.36
2015 (Predecessor)							
First Quarter	685	426	10.7	2,902	$45.10	$16.09	$2.76
Second Quarter	628	366	10.4	2,725	$56.65	$15.18	$2.61
Third Quarter	581	344	10.8	2,734	$45.24	$12.94	$2.70
Fourth Quarter	511	297	11.9	2,785	$40.22	$13.38	$2.20
Total	2,405	1,433	43.8	11,146	$47.11	$14.54	$2.56
2016 (Predecessor)							
First Quarter	427	310	9.2	2,269	$30.07	$10.83	$1.98
April 1 - April 22	95	70	2.2	538	$37.49	$11.96	$1.90
Total	522	380	11.4	2,807	$31.43	$11.04	$1.96
(Successor)							
April 23 - June 30	254	246	8.1	1,844	$44.35	$14.15	$1.97
Third Quarter	292	255	11.5	2,463	$43.27	$16.38	$2.71
Fourth Quarter	240	226	9.5	2,058	$47.10	$18.84	$2.86
Total	786	727	29.1	6,365	$44.79	$16.39	$2.55

For the period of April 23, 2016 through December 31, 2016 (successor) and the years ended December 31, 2015 and 2014 (predecessor), we recorded net gains (losses) of ($19.7) million, $0.2 million and $1.3 million, respectively, related to our derivative activities. There were no hedges in place for the period of January 1, 2016 through April 22, 2016 (predecessor). This activity is recorded in "Price-risk management and other, net" on the accompanying consolidated statements of operations.

Costs and Expenses

2016 - During 2016, our cost and expenses were as follows:

Lease Operating Cost. These expenses on a per Boe basis were $4.05, $5.32 and $6.30 for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The decrease in the successor period was primarily due to lower workover, labor, compression, chemicals, maintenance, and salt water disposal costs primarily driven by concentrated efforts to reduce operating costs.

Transportation and gas processing. These expenses all related to gas and NGL sales. These expenses on a per Mcf basis were $0.45, $0.53 and $0.50 for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The lower rates for the most recent period were primarily attributable to improved negotiated rates for certain South Texas fields.

Depreciation, Depletion and Amortization ("DD&A"). These expenses on a per Boe basis were $5.72, $7.28 and $15.93 for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The depletion expense recorded subsequent to April 22, 2016 is not comparable to prior periods due to the restatement of assets at their fair value upon emergence from bankruptcy. The decreased per Boe amount from the year ended December 31, 2015 (predecessor) compared to the period of January 1, 2016 through April 22, 2016 (predecessor) is attributable to a lower depletable base due to ceiling test write-downs in the second half of 2015.

General and Administrative Expenses, Net. These expenses on a per Boe basis were $3.54, $3.29 and $3.82 for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The decrease from the year ended December 31, 2015 (predecessor) was primarily due to lower salaries and burdens, a lower corporate benefit accrual and lower legal and professional fees, partially offset by severance and equity compensation expense for retiring executives, and lower capitalized amounts.

Severance and Other Taxes. These expenses on a per Boe basis were $1.05, $1.40 and $1.53 for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The decrease in the successor period was primarily driven by lower oil and gas revenues as a result of decreased commodity prices along with declining oil and gas production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 5.5%, 9.1% and 6.9% for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively. The reduction as a percentage of revenue in the most recent period is primarily attributable to lower Louisiana oil sales taxed at higher rates in proportion to total revenue.

Interest. Our gross interest cost was $15.8 million, $13.3 million and $80.8 million for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively, of which $0.5 million was capitalized for the period of April 23, 2016 through December 31, 2016 (successor) and $4.9 million was capitalized for the year ended December 31, 2015 (predecessor). The decrease in gross interest from 2016 was primarily due to the discontinuance of interest on our senior notes due to our bankruptcy proceedings, partially offset by interest expense related to the DIP Credit Agreement.

Write-down of oil and gas properties. Primarily due to pricing differences between the 12-month average oil and gas prices used in the Ceiling Test, as defined below, and the forward strip prices used to estimate the initial fair value of oil and gas properties on the Company's April 22, 2016 (successor) balance sheet, we recorded a write-down of $133.5 million during the period of April 23, 2016 through December 31, 2016 (successor). The full amount of this write-down was incurred at June 30, 2016. Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded non-cash write-downs on a before-tax basis of $77.7 million during the period of January 1, 2016 through April 22, 2016 (predecessor).

Reorganization Items. We incurred a net gain of $956.1 million for the period of January 1, 2016 through April 22, 2016 (predecessor) and expenses of $1.6 million and $6.6 million for the period of April 23, 2016 through December 31, 2016 (successor) and year ended December 31, 2015 (predecessor). The net gain was primarily due to the gain on discharge of debt and fresh start adjustments upon emergence from bankruptcy.

Income Taxes. The Company entered bankruptcy with Federal and state net operating loss carryovers and amortizable property basis significantly in excess of book value. This resulted in the Company having significant deferred tax assets. Given our recent history of incurring tax losses and economic uncertainty we recorded a full valuation allowance against these tax assets. The Company's emergence from bankruptcy resulted in a significant tax gain on the debt conversion to equity. We will be able to fully offset this gain with our net operating losses. Since these net operating losses carried a zero book balance after valuation allowances there was no tax expense realized as a result of the gain reported for the period of January 1, 2016 through April 22, 2016 (predecessor). There was no benefit for income taxes in the period of April 23, 2016 through December 31, 2016 (successor) as the benefit for the periods was offset with valuation allowances. The tax benefit of $80.5 million for the year ended December 31, 2015 (predecessor) was due to a reduction in our deferred tax liability resulting from the write-down of oil and gas properties, partially offset by a valuation allowance.

2015 - As 2015 and 2014 were both predecessor periods, the variances below are presented on a year-over-year basis. Our expenses in 2015 decreased $126.9 million when compared to those in 2014 (excluding the 2015 and 2014 ceiling test write-downs and 2015 reorganization items resulting from the Company's bankruptcy proceedings), for the reasons noted below. During 2015, we saw a decrease in the cost of services and supplies due to the decline in commodity prices.

Lease Operating Cost. These expenses decreased $23.0 million, or 25%, compared to the level of such expenses for the year ended December 31, 2014, primarily due to lower labor costs, maintenance costs, salt water disposal costs and lower supervision fees (i.e. overhead rates) charged to LOE. Our lease operating costs per Boe produced were $5.99 and $7.52 for the years ended December 31, 2015 and 2014, respectively.

Transportation and gas processing. These expenses increased $0.6 million, or 3%, compared to the level of such expenses for the year ended December 31, 2014. Our transportation and gas processing costs per Boe produced were $1.85 and $1.71 for the years ended December 31, 2015 and 2014, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses decreased $90.1 million, or 34%, from those during the year ended December 31, 2014, due to decreased production and a lower depletable base. Our DD&A rate per Boe of production was $15.14 and $21.60 for the years ended December 31, 2015 and 2014, respectively.

General and Administrative Expenses, Net. These expenses increased $3.0 million or 8%, compared to the level of such expenses for the year ended December 31, 2014, due to higher legal and professional fees and lower capitalized costs, partially offset by lower salaries and burdens, lower temporary labor and lower stock compensation . For the years ended December 31, 2015 and 2014, our capitalized general and administrative costs totaled $12.7 million and $26.3 million, respectively. Our net general and administrative expenses per Boe produced were $3.63 and $3.20 for the years ended December 31, 2015 and 2014, respectively. The supervision fees recorded as a reduction to general and administrative expenses were $9.2 million and $12.7 million for the years ended December 31, 2015 and 2014, respectively.

Severance and Other Taxes. These expenses decreased $19.9 million, or 54%, from the year ended December 31, 2014. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.9% and 6.8% for the years ended December 31, 2015 and 2014, respectively.

Interest. Our gross interest cost for the year ended December 31, 2015 was $80.8 million, of which $4.9 million was capitalized. Our gross interest cost for the year ended December 31, 2014 was $78.2 million, of which $5.0 million was capitalized. The increase in interest came from increased credit facility borrowings during 2015.

Write-down of oil and gas properties. Due to the effects of pricing, timing of projects, changes in our reserves product mix, and our bankruptcy filing as discussed in Note 1A, in 2015 we reported non-cash write-downs on a before-tax basis of $1.6 billion ($1.5 billion after tax). In 2014 we reported non-cash write-downs on a before-tax basis of $445.4 million ($287.3 million after tax), for our oil and natural gas properties.

Reorganization Items. Incurred $6.6 million expense for the year ended December 31, 2015 due to the write-off of debt issuance costs, premiums and discounts associated with our senior notes as a result of our bankruptcy filing.

Income Taxes. Our effective income tax rate was 4.6% for the year ended December 31, 2015. For the year ended December 31, 2014 the rate was 34.6%. These were below the U.S. Federal statutory rate due to valuation allowances offsetting tax benefits of recorded losses.

Critical Accounting Policies and New Accounting Pronouncements

Fresh start Accounting. Upon emergence from bankruptcy, we adopted fresh start accounting, which resulted in the Company becoming a new entity for financial reporting purposes. Upon adoption of fresh start accounting, our assets and liabilities were recorded at their fair values as of the Effective Date. The Effective Date fair values of our assets and liabilities differed materially from the recorded values of our assets and liabilities as reflected in our historical consolidated balance sheets. The effects of the Reorganization Plan and the application of fresh start accounting were implemented as of April 22, 2016 and the related adjustments thereto were recorded in our consolidated statement of operations as reorganization items for the period of January 1, 2016 through April 22, 2016.

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 on a property-by-property basis 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 the impairment 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").

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.

If future capital expenditures outpace 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, it is possible that non-cash write-downs of our oil and natural gas properties will 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.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersede current revenue recognition guidance. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017.

The Company's revenues are virtually all attributable to oil and gas sales. Based on our initial review of our contracts, the Company believes the timing and presentation of revenues under ASU 2014-09 will be consistent with our current revenue recognition policy as described above with one probable exception. The Company currently uses the entitlement method of accounting when sales for our account are not in proportion to ownership interest in production. To comply with ASU 2014-09, the Company expects to recognize revenue on the production sold for our account irrespective of ownership share of such production. Currently we do not have any significant imbalance situations; therefore, this is not expected to immediately impact our financial statements. The Company will continue to monitor specific developments for our industry as it relates to ASU 2014-09.

In August 2014, the FASB issued ASU 2014-15, which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. The guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter. We implemented procedures to comply with this guidance as of December 31, 2016. Adoption of this standard had no impact on our financial statements.

In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.

At December 31, 2016 the Company had lease commitments of approximately $8.8 million that it believes would be subject to capitalization under ASU 2016-02. This includes $1.9 million for our corporate office sub-lease which has a term of 4.4 years and commitments for equipment and vehicle leases which total $6.5 million. These equipment leases generally have original terms of 2 - 3 years. In some instances further analysis is needed to determine if renewal options would result in capitalized amounts in excess of the obligations during the primary lease term. Based on our preliminary assessment, we believe these leases would most likely be deemed to be operating leases under the new standard. The corporate office sub-lease is the only existing lease that extends beyond December 31, 2018. Management plans to adopt ASU 2016-02 in the quarter ending March 31, 2019. Management continuously evaluates the economics of leasing vs. purchase for operating equipment. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than the current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

In March 2016, the FASB issued ASU 2016-09, which simplifies several aspects of the accounting for employee share based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, with early adoption permitted. This standard was adopted by the Company as of the bankruptcy emergence date April 22, 2016. There were no equity awards in place at the time of emergence from bankruptcy and the adoption of this guidance did not result in any adjustments.

In August 2016, the FASB issued ASU 2016-15, which provides greater clarity to preparers on the treatment of eight specific items within an entity's statement of cash flows with the goal of reducing existing diversity on these items. The guidance is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, including adoption in an interim period. We are currently reviewing these new requirements. Implementation may result in presentation changes to our Statements of Cash Flows but we do not expect it to impact any of our other financial statements.

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:

- future cash flows and their adequacy to maintain our ongoing operations;
- oil and natural gas pricing expectations;
- liquidity, including our ability to satisfy our short- or long-term liquidity needs;
- business strategy, including our business strategy post-emergence from bankruptcy;
- estimated oil and natural gas reserves or the present value thereof;
- our borrowing capacity, future covenant compliance, cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- asset disposition efforts or the timing or outcome thereof;
- ongoing and 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, cost and amount of future production of oil and natural gas;
- availability of drilling and production equipment or availability of oil field labor;
- availability, cost and terms of capital;
- drilling of wells;
- availability and cost for 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; and
- plans, objectives, expectations and intentions contained in this report that are not historical.
- uncertainty of our ability to improve our operating structure, financial results and profitability following emergence from Chapter 11 and other risk and uncertainties related to our emergence from Chapter 11;
- new capital structure and the adoption of fresh start accounting, including the risk that assumptions and factors used in estimating enterprise value vary significantly from the current estimates in connection with the application of fresh start accounting;
- ability to have our common stock listed on a national securities exchange; and

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 this annual report on Form 10-K for the year ended December 31, 2016. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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 6 of the consolidated financial statements in this Form 10-K.

Income Tax Carryforwards. As of December 31, 2016, the Company has net deferred tax carryforward assets of $40.1 million for federal net operating losses and $2.1 million for federal alternative minimum tax credits. In management's judgment it is more likely than not that the company will not be able to utilize these carryforward assets to reduce future taxes. Accordingly these carryovers are all fully reserved by a valuation allowance.

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. During our most recent reporting period of April 23, 2016 through December 31, 2016, 38%, 15% and 14% for our oil and gas has been sold to Kinder Morgan and affiliates, Shell Oil Corporation and affiliates, and Plains Marketing and affiliates, respectively. We expect to continue these relationships in the future. We believe that the risk of these unsecured receivables is mitigated by the size, reputation and nature of these businesses and the availability of other purchasers in the areas where we operate.

Interest Rate Risk. At December 31, 2016, we had $198.0 million drawn under our credit facility, which bears a floating rate of interest depending on the level of the non-conforming borrowing base and the non-conforming borrowing base loans outstanding and therefore is susceptible to interest rate fluctuations.

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, 2016. 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, 2016.

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.

BDO USA, LLP, the independent registered public accounting firm that audited the 2016 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, 2016, based on their audit.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Swift Energy Company
Houston, Texas

We have audited Swift Energy Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Swift Energy Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, 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 sheet of Swift Energy Company as of December 31, 2016 (Successor), and the related consolidated statements of operations, stockholders' equity, and cash flows for the periods from April 23, 2016 through December 31, 2016 (Successor) and January 1, 2016 through April 22, 2016 (Predecessor) and our report dated February 27, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 27, 2017

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Swift Energy Company
Houston, Texas

We have audited the accompanying consolidated balance sheet of Swift Energy Company as of December 31, 2016 (Successor) and the related consolidated statements of operations, stockholders' equity, and cash flows for the periods from April 23, 2016 through December 31, 2016 (Successor), and January 1, 2016 through April 22, 2016 (Predecessor). These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 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, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Swift Energy Company at December 31, 2016 (Successor) and the results of its operations and its cash flows for the periods from April 23, 2016 through December 31, 2016 (Successor) and January 1, 2016 through April 22, 2016 (Predecessor), in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1A to the consolidated financial statements, the Company emerged from bankruptcy on April 22, 2016. Accordingly, the accompanying consolidated financial statements have been prepared in conformity with Accounting Standards Codification 852-10, *Reorganizations*, for the Successor as a new entity with assets, liabilities and a capital structure having carrying amounts not comparable with prior periods as described in Note 1B.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Swift Energy Company's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2017 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP

Houston, Texas
February 27, 2017

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 (debtor-in-possession) (the "Company") as of December 31, 2015, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years ended December 31, 2015 and 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 (debtor-in-possession) at December 31, 2015, and the consolidated results of their operations and their cash flows for each of the years ended December 31, 2015 and December 31, 2014, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1A to the financial statements, Swift Energy Company (debtor-in-possession) filed for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code on December 31, 2015. This condition raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters also are described in Note 1A. The 2015 consolidated financial statements do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty.

/s/ ERNST & YOUNG LLP

Houston, Texas
March 4, 2016

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

	Successor	Predecessor
	December 31, 2016	December 31, 2015
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 303	$ 29,460
Accounts receivable, net	17,490	21,704
Other current assets	3,686	10,683
Total Current Assets	21,479	61,847
Property and Equipment:		
Property and Equipment, Full Cost Method, including $33,354 and $18,839 of unproved property costs not being amortized	517,074	6,035,757
Less – Accumulated depreciation, depletion, amortization and impairment	(169,879)	(5,577,854)
Property and Equipment, Net	347,195	457,903
Other Long-Term Assets	8,625	5,248
Total Assets	$ 377,299	$ 524,998
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 56,257	$ 7,663
Accrued capital costs	11,954	—
Accrued interest	1,721	490
Undistributed oil and gas revenues	9,192	—
Current portion of long-term debt	—	324,900
Total Current Liabilities	79,124	333,053
Long-term debt	198,000	—
Asset retirement obligations	22,291	56,390
Other long-term liabilities	1,829	3,891
Liabilities subject to compromise	—	984,388
Commitments and Contingencies (Note 7)	—	—
Stockholders' Equity (Deficit):		
Predecessor Common stock, $.01 par value, 150,000,000 shares authorized, 44,771,258 shares issued, and 44,591,863 shares outstanding	—	448
Predecessor Additional paid-in capital	—	776,358
Predecessor Treasury stock held, at cost, 179,395 shares	—	(2,491)
Successor Preferred stock, $.01 par value, 10,000,000 shares authorized, none outstanding	—	—
Successor Common stock, $.01 par value, 40,000,000 shares authorized, 10,076,059 shares issued and 10,053,574 shares outstanding	101	—
Successor Additional paid-in capital	232,917	—
Successor Treasury stock held, at cost, 22,485 shares	(675)	—
Accumulated deficit	(156,288)	(1,627,039)
Total Stockholders' Equity (Deficit)	76,055	(852,724)
Total Liabilities and Stockholders' Equity (Deficit)	$ 377,299	$ 524,998

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

Swift Energy Company and Subsidiaries (in thousands, except per-share amounts)

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Revenues:				
Oil and gas sales	$ 121,386	$ 43,027	$ 246,270	$ 547,790
Price-risk management and other, net	(19,849)	(245)	(1,549)	1,666
Total Revenues	101,537	42,782	244,721	549,456
Costs and Expenses:				
General and administrative, net	22,538	9,245	42,611	39,629
Depreciation, depletion, and amortization	36,436	20,439	177,512	267,590
Accretion of asset retirement obligation	2,878	1,610	5,572	5,712
Lease operating expense	25,777	14,933	70,188	93,214
Transportation and gas processing	13,038	6,090	21,741	21,140
Severance and other taxes	6,713	3,917	17,090	37,038
Interest expense, net	15,310	13,347	75,870	73,207
Write-down of oil and gas properties	133,496	77,732	1,562,086	445,396
Reorganization items	1,639	(956,142)	6,565	—
Total Costs and Expenses	257,825	(808,829)	1,979,235	982,926
Income (Loss) Before Income Taxes	(156,288)	851,611	(1,734,514)	(433,470)
Income Taxes	—	—	(80,543)	(150,043)
Net Income (Loss)	$ (156,288)	$ 851,611	$ (1,653,971)	$ (283,427)
Per Share Amounts-				
Basic: Net Income (Loss)	$ (15.61)	$ 19.06	$ (37.20)	$ (6.47)
Diluted: Net Income (Loss)	$ (15.61)	$ 18.64	$ (37.20)	$ (6.47)
Weighted Average Shares Outstanding - Basic	10,013	44,692	44,463	43,795
Weighted Average Shares Outstanding - Diluted	10,013	45,697	44,463	43,795

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity (Deficit)

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Deficit)	Total
Balance, December 31, 2013 (Predecessor)	$ 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)	—	—	—
Share-based compensation	—	10,787	—	—	10,787
Net Loss	—	—	—	(283,427)	(283,427)
Balance, December 31, 2014 (Predecessor)	$ 444	$ 771,972	$ (9,855)	$ 31,817	$ 794,378
Stock issued for benefit plans (352,476 shares)	—	(1,714)	7,518	(4,885)	919
Purchase of treasury shares (70,437 shares)	—	—	(154)	—	(154)
Employee stock purchase plan (87,629 shares)	1	301	—	—	302
Issuance of restricted stock (304,166 shares)	3	(3)	—	—	—
Share-based compensation	—	5,802	—	—	5,802
Net Loss	—	—	—	(1,653,971)	(1,653,971)
Balance, December 31, 2015 (Predecessor)	$ 448	$ 776,358	$ (2,491)	$(1,627,039)	$ (852,724)
Purchase of treasury shares (65,170 shares)	—	—	(5)	—	(5)
Issuance of restricted stock (229,690 shares)	2	(2)	—	—	—
Share-based compensation	—	1,118	—	—	1,118
Net Income	—	—	—	851,611	851,611
Balance, April 22, 2016 (Predecessor)	$ 450	$ 777,474	$ (2,496)	$ (775,428)	$ —
Cancellation of Predecessor equity	(450)	(777,474)	2,496	775,428	—
Balance, April 22, 2016 (Predecessor)	$ —	$ —	$ —	$ —	$ —
Issuance of Successor common stock & warrants	100	229,299	—	—	229,399
Balance, April 22, 2016 (Successor)	$ 100	$ 229,299	$ —	$ —	$ 229,399
Purchase of treasury shares (22,485 shares)	—	—	(675)	—	(675)
Issuance of restricted stock (76,058 shares)	1	—	—	—	1
Share-based compensation	—	3,618	—	—	3,618
Net Loss	—	—	—	(156,288)	(156,288)
Balance, December 31, 2016 (Successor)	$ 101	$ 232,917	$ (675)	$ (156,288)	$ 76,055

See accompanying Notes to Consolidated Financial Statements.

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

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Cash Flows from Operating Activities:				
Net income (loss)	$ (156,288)	$ 851,611	$ (1,653,971)	$ (283,427)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities-				
Write-down of oil and gas properties	133,496	77,732	1,562,086	445,396
Depreciation, depletion, and amortization	36,436	20,439	177,512	267,590
Accretion of asset retirement obligation	2,878	1,610	5,572	5,712
Deferred income taxes	—	—	(80,133)	(150,357)
Share-based compensation expense	3,618	886	4,435	7,309
Loss (gain) on derivatives	19,676	—	(186)	(1,269)
Cash settlements on derivatives	(1,928)	—	2,544	(1,053)
Reorganization items (non-cash)	—	(977,696)	6,565	—
Other	1,351	229	(3,189)	(6,588)
Change in operating assets and liabilities-				
(Increase) decrease in accounts receivable and other assets	16,812	(5,474)	26,747	21,411
Increase (decrease) in accounts payable and accrued liabilities	(9,682)	(10,495)	(15,003)	1,505
Increase (decrease) in income taxes payable	—	—	(435)	314
Increase (decrease) in accrued interest	1,058	(308)	9,730	(172)
Net Cash Provided by (Used in) Operating Activities	47,427	(41,466)	42,274	306,371
Cash Flows from Investing Activities:				
Additions to property and equipment	(45,671)	(24,530)	(139,688)	(386,336)
Proceeds from the sale of property and equipment	45,985	48,661	1,164	145,035
Funds withdrawn from restricted cash account	—	—	—	25,994
Funds deposited into restricted cash account	—	—	—	(25,994)
Net Cash Provided by (Used in) Investing Activities	314	24,131	(138,524)	(241,301)
Cash Flows from Financing Activities:				
Proceeds from bank borrowings	84,000	328,000	281,100	487,400
Payments of bank borrowings	(139,000)	(324,900)	(153,500)	(555,100)
Net proceeds from issuances of common stock	—	—	302	824
Purchase of treasury shares	(675)	(4)	(154)	(1,065)
Payments of debt issuance costs	(502)	(6,482)	(2,444)	—
Net Cash Provided by (Used in) Financing Activities	(56,177)	(3,386)	125,304	(67,941)
Net Increase (Decrease) in Cash and Cash Equivalents	(8,436)	(20,721)	29,054	(2,871)
Cash and Cash Equivalents at Beginning of Period	8,739	29,460	406	3,277
Cash and Cash Equivalents at End of Period	$ 303	$ 8,739	$ 29,460	$ 406
Supplemental Disclosures of Cash Flows Information:				
Cash paid during period for interest, net of amounts capitalized	12,517	10,367	63,132	70,933
Cash paid during period for income taxes	—	—	450	150
Cash paid for reorganization items	12,929	15,643	—	—
Changes in capital accounts payable and capital accruals	(6,265)	1,843	(27,611)	(21,702)

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1A. Emergence from Voluntary Reorganization under Chapter 11 Proceedings

On December 31, 2015, Swift Energy Company ("Swift Energy," the "Company" or "we") and eight of its U.S. subsidiaries (the "Chapter 11 Subsidiaries") filed voluntary petitions seeking relief under Chapter 11 of Title 11 of the U.S. Bankruptcy Code (the "Bankruptcy Code") in the U.S. Bankruptcy Court for the District of Delaware under the caption *In re Swift Energy Company, et al* (Case No. 15-12670). The Company and the Chapter 11 Subsidiaries received bankruptcy court confirmation of their joint plan of reorganization (the "Plan") on March 31, 2016, and subsequently emerged from bankruptcy on April 22, 2016 (the "Effective Date").

Effect of the Bankruptcy Proceedings. During the bankruptcy proceedings, the Company conducted normal business activities and was authorized to pay and has paid (subject to caps applicable to payments of certain pre-petition obligations) pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders and critical vendors, pre-petition amounts owed to pipeline owners that transport the Company's production, and funds belonging to third parties, including royalty holders and partners.

In addition, subject to certain specific exceptions under the Bankruptcy Code, the Chapter 11 filings automatically stayed most judicial or administrative actions against the Company and efforts by creditors to collect on or otherwise exercise rights or remedies with respect to pre-petition claims. As a result, we did not record interest expense on the Company's senior notes for the period of January 1, 2016 through April 22, 2016 (as the predecessor). For that period, contractual interest on the senior notes totaled $21.6 million.

Plan of Reorganization. Pursuant to the Plan, the significant transactions that occurred upon emergence from bankruptcy were as follows:

- the approximately $906 million of indebtedness outstanding on account of the Company's senior notes, $75 million in borrowings under the Company's DIP Credit Agreement (described below) and certain other unsecured claims were exchanged for 88.5% of the post-emergence Company's common stock;
- the lenders under the DIP Credit Agreement (as defined and more fully described below) received an additional backstop fee consisting of 7.5% of the post-emergence Company's common stock;
- the Company's pre-petition common stock was canceled and the current shareholders received 4% of the post-emergence Company's common stock and warrants to purchase up to 30% of the reorganized Company's equity. See Note 1B of these consolidated financial statements for more information;
- claims of other creditors were paid in full in cash, reinstated or otherwise treated in a manner acceptable to the creditors;
- the Company entered into a registration rights agreement to provide customary registration rights to certain holders of the Company's post-emergence common stock who, together with their affiliates received upon emergence 5% or more of the outstanding common stock of the Company;
- the Company sold (effective April 15, 2016) a portion of its interest in its Central Louisiana fields known as Burr Ferry and South Bearhead Creek to Texegy LLC, for net proceeds of approximately $46.9 million including deposits received prior to the closing date; and
- the Company's previous credit facility (the "Prior First Lien Credit Facility") was terminated and a new senior secured credit facility (the "New Credit Facility") with an initial $320 million borrowing base was established. For more information refer to Note 5 of these consolidated financial statements.

In accordance with the Plan, the post-emergence Company's new board of directors is made up of seven directors consisting of the Chief Executive Officer, two directors appointed by Strategic Value Partners LLC ("SVP"), a former holder of the Company's senior notes, two directors appointed by other former holders of the Company's senior notes, one independent director and one independent non-executive chairman of the Board. In addition, pursuant to the Plan, SVP and the other former holders of the Company's senior notes were given certain continuing director nomination rights subject to minimum share ownership conditions.

DIP Credit Agreement. In connection with the pre-petition negotiations of the restructuring support agreement, certain holders of the Company's senior notes agreed to provide the Company and the Chapter 11 Subsidiaries a debtor in possession facility (the "DIP Credit Agreement"). The DIP Credit Agreement provided for a multi-draw term loan of up to $75.0 million, which became available to the Company upon the satisfaction of certain milestones and contingencies. Upon emergence from bankruptcy, the Company had drawn down the entire $75.0 million available. Pursuant to the Plan, the borrowings under the DIP Credit Agreement, at the option of the lenders to the DIP Credit Agreement, converted into the post-emergence Company's common stock, which was part of the 88.5% of the common stock distributed to the holders of the Company's senior notes and certain unsecured creditors. As such, the $75.0 million borrowed under the DIP Credit Agreement was not required to be repaid in cash and terminated upon the Company's exit from bankruptcy. For more information refer to Note 5 of these consolidated financial statements.

Financial Statement Classification of Liabilities Subject to Compromise. As of December 31, 2015, our financial statements included amounts classified as liabilities subject to compromise, a majority of which were equitized upon emergence from bankruptcy on April 22, 2016. See Note 1B of these consolidated financial statements for more information.

1B. Fresh Start Accounting

Upon the Company's emergence from Chapter 11 bankruptcy, the Company adopted fresh start accounting, pursuant to FASB ASC 852, "*Reorganizations"*, and applied the provisions thereof to its consolidated financial statements. The Company qualified for fresh start accounting because (i) the holders of existing voting shares of the pre-emergence debtor-in-possession, referred to herein as the "Predecessor" or "Predecessor Company," received less than 50% of the voting shares of the post-emergence successor entity, which we refer to herein as the "Successor" or "Successor Company" and (ii) the reorganization value of the Company's assets immediately prior to confirmation was less than the post-petition liabilities and allowed claims. The Company applied fresh start accounting following the close of business on April 22, 2016 when it emerged from bankruptcy protection. Adopting fresh start accounting results in a new reporting entity for financial reporting purposes with no beginning retained earnings or deficit. The cancellation of all existing shares outstanding on the Effective Date and issuance of new shares of the Successor Company caused a related change of control of the Company under ASC 852. As a result of the application of fresh start accounting, as well as the effects of the implementation of the Plan, the consolidated financial statements as of April 23, 2016 forward are not comparable with the consolidated financial statements prior to that date. References to "Successor" or "Successor Company" relate to the financial position and results of operations of the reorganized Company subsequent to April 22, 2016. References to "Predecessor" or "Predecessor Company" refer to the financial position and results of operations of the Company prior to and including April 22, 2016.

Reorganization Value. Reorganization value represents the fair value of the Successor Company's total assets and is intended to approximate the amount a willing buyer would pay for the assets immediately before restructuring. Under fresh start accounting, we allocated the reorganization value to our individual assets based on their estimated fair values.

Our reorganization value was derived from an estimate of enterprise value. Enterprise value represents the estimated fair value of an entity's long term debt and shareholders' equity. In support of the Plan, the enterprise value of the Successor Company was estimated and approved by the bankruptcy court to be in the range of $460 million to $800 million. Based on the estimates and assumptions used in determining the enterprise value, as further discussed below, the Company estimated the enterprise value to be approximately $474 million. This valuation analysis was prepared using reserve information, development schedules, other financial information and financial projections and applying standard valuation techniques, including risked net asset value analysis and public comparable company analyses.

Valuation of Oil and Gas Properties. The Company's principal assets are its oil and gas properties, which the Company accounts for under the Full Cost Accounting method as described in Note 2. With the assistance of valuation experts, the Company determined the fair value of its oil and gas properties based on the discounted cash flows expected to be generated from these assets. The computations were based on market conditions and reserves in place as of the bankruptcy emergence date.

The Company's Reserves Engineers developed full cycle production models for all of the Company's developed wells and identified undeveloped drilling locations within the Company's leased acreage. The undeveloped locations were categorized based on varying levels of risk using industry standards. The proved locations were limited to wells expected to be drilled in the Company's five year plan. The locations were then segregated into geographic areas. Future cash flows before application of risk factors were estimated by using the New York Mercantile Exchange five year forward prices for West Texas Intermediate oil and Henry Hub natural gas with inflation adjustments applied to periods beyond five years. These prices were adjusted for typical differentials realized by the Company for location and product quality adjustments. Transportation cost estimates were based on agreements in place at the emergence date. Development and operating costs were based the Company's recent cost trends adjusted for inflation.

Risk factors were determined separately for each geographic area. Based on the geological characteristics of each area appropriate risk factors for each of the reserve categories were applied. The Company and its valuation experts considered production, geological and mechanical risk to determine the probability factor for each reserve category in each area.

The risk adjusted after tax cash flows were discounted at 12%. This discount factor was derived from a weighted average cost of capital computation which utilized a blended expected cost of debt and expected returns on equity for similar industry participants. The after tax cash flow computations included utilization of the Company's unamortized tax basis in the properties as of the emergence date. Plugging and abandonment costs were included in the cash flow projections for undeveloped reserves but were excluded for developed reserves since the fair value of this liability was determined separately and included in the emergence date liabilities reported on the consolidated balance sheet.

From this analysis the Company concluded the fair value of its proved reserves was $509.4 million, and the value of its probable reserves was $45.5 million as of the Effective Date. The fair value of the possible reserves was determined to be de minimus and no value therefore recognized. The value of probable reserves was classified as unevaluated costs. The Company also reviewed its undeveloped leasehold acreage and concluded that the fair value of its probable reserves appropriately captured the fair value of its undeveloped leasehold acreage. These amounts are reflected in the Fresh Start Adjustments item number 12 below.

The following table reconciles the enterprise value to the estimated fair value of the Successor Company's common stock as of the Effective Date (in thousands):

		April 22, 2016
Enterprise Value	$	473,660
Plus: Cash and cash equivalents		8,739
Less: Fair value of debt		(253,000)
Less: Fair value of warrants		(14,967)
Fair value of Successor common stock	$	214,432
Shares outstanding at April 22, 2016		10,000
Per share value	$	21.44

Upon issuance of the New Credit Facility on April 22, 2016, the Company received net proceeds of approximately $253 million and incurred debt issuance costs of approximately $7.0 million.

In accordance with the Plan, the Company issued two series of warrants (each for up to 15% of the reorganized Company's equity) to the former holders of the Company's common stock, one to expire on the close of business on April 22, 2019 (the "2019 Warrants") and the other to expire on the close of business on April 22, 2020 (the "2020 Warrants" and, together with the 2019 Warrants, the "Warrants"). Following the Effective Date, there were 2019 Warrants outstanding to purchase up to an aggregate of 2,142,857 shares of Common Stock at an initial exercise price of $80.00 per share. Following the Effective Date, there were 2020 Warrants outstanding to purchase up to an aggregate of 2,142,857 shares of Common Stock at an initial exercise price of $86.18 per share. All unexercised Warrants shall expire, and the rights of the holders of such Warrants to purchase Common Stock shall terminate at the close of business on the first to occur of (i) their respective expiration dates or (ii) the date of completion of (A) any Fundamental Equity Change (as defined in the Warrant Agreement) or (B) an Asset Sale (as defined in the Warrant Agreement). The fair value of the 2019 and 2020 Warrants was $3.26 and $3.73 per warrant, respectively. A Black- Scholes pricing model with the following assumptions was used in determining the fair value: strike price of $80 and $86.18; expected volatility of 70% and 65%; expected dividend rate of 0.0%; risk free interest rate of 1.01% and 1.19%; and expiration date of 3 and 4 years, respectively. The fair value of these warrants was estimated using Level 2 inputs (for additional discussion of the Level 2 inputs, refer to Note 11 of these consolidated financial statements).

The following table reconciles the enterprise value to the estimated reorganization value as of the Effective Date (in thousands):

		April 22, 2016
Enterprise Value	$	473,660
Plus: Cash and cash equivalents		8,739
Plus: Other working capital liabilities		73,318
Plus: Other long-term liabilities		58,992
Reorganization value of Successor assets	$	614,709

Reorganization value and enterprise value were estimated using numerous projections and assumptions that are inherently subject to significant uncertainties and resolution of contingencies that are beyond our control. Accordingly, the estimates set forth herein are not necessarily indicative of actual outcomes, and there can be no assurance that the estimates, projections or assumptions will be realized.

Consolidated Balance Sheet. The adjustments set forth in the following consolidated balance sheet reflect the effect of the consummation of the transactions contemplated by the Plan (reflected in the column "Reorganization Adjustments") as well as fair value adjustments as a result of the adoption of fresh start accounting (reflected in the column "Fresh Start Adjustments"). The explanatory notes highlight methods used to determine fair values or other amounts of the assets and liabilities as well as significant assumptions.

The following table reflects the reorganization and application of ASC 852 on our consolidated balance sheet as of April 22, 2016 (in thousands):

	Predecessor Company	Reorganization Adjustments		Fresh Start Adjustments		Successor Company
ASSETS						
Current Assets:						
Cash and cash equivalents	$ 57,599	$ (48,860)	(1)	$ —		$ 8,739
Accounts receivable	34,278	(597)	(2)	—		33,681
Other current assets	3,503	—		—		3,503
Total current assets	95,380	(49,457)		—		45,923
Property and equipment	6,007,326	—		(5,448,759)	(12)	558,567
Less - accumulated depreciation, depletion and amortization	(5,676,252)	—		5,676,252	(12)	—
Property and equipment, net	331,074	—		227,493		558,567
Other Long-Term Assets	4,629	6,388	(3)	(798)	(13)	10,219
Total Assets	$ 431,083	$ (43,069)		$ 226,695		$ 614,709

	Predecessor Company	Reorganization Adjustments		Fresh Start Adjustments		Successor Company
LIABILITIES AND STOCKHOLDERS' EQUITY						
Current Liabilities:						
Accounts payable and accrued liabilities	$ 64,324	$ (4,666)	(4)	$ (885)	(14)	$ 58,773
Accrued capital costs	5,410	—		—		5,410
Accrued interest	768	(104)	(5)	—		664
Undistributed oil and gas revenues	8,471	—		—		8,471
Current portion of debt	364,500	(364,500)	(6)	—		—
Total current liabilities	443,473	(369,270)		(885)		73,318
Long-Term Debt	—	253,000	(7)	—		253,000
Asset retirement obligation	51,800	—		6,101	(14)	57,901
Other long-term liabilities	2,124	—		(1,033)	(15)	1,091
Liabilities subject to compromise	911,381	(911,381)	(8)	—		—
Total Liabilities	1,408,778	(1,027,651)		4,183		385,310
Stockholders' Equity:						
Preferred stock		—		—		—
Common stock (Predecessor)	450	(450)	(9)	—		—
Common stock (Successor)	—	100	(10)	—		100
Additional paid-in capital (Predecessor)	777,475	(777,475)	(9)	—		—
Additional paid-in capital (Successor)	—	229,299	(10)	—		229,299
Treasury stock held at cost	(2,496)	2,496	(9)	—		—
Retained earnings (accumulated deficit)	(1,753,124)	1,530,612	(11)	222,512	(16)	—
Total Stockholders' Equity (Deficit)	(977,695)	984,582		222,512		229,399
Total Liabilities and Stockholders' Equity	$ 431,083	$ (43,069)		$ 226,695		$ 614,709

Reorganization Adjustments

1. Reflects the net cash payments recorded as of the Effective Date from implementation of the Plan (in thousands):

Sources:		
Net proceeds from New Credit Facility		253,000
Total Sources	$	253,000
Uses:		
Repayment of Prior First Lien Credit Facility		289,500
Debt issuance costs		6,482
Predecessor accounts payable paid upon emergence		5,878
Total Uses	$	301,860
Net Uses	$	(48,860)

2. Reflects the impairment of a short-term leasehold improvement build-out receivable for $0.6 million that will no longer be reimbursed by the building lessor as the Company's office lease contract was rejected as part of the bankruptcy.

3. Reflects the capitalization of debt issuance costs on the New Credit Facility for $7.0 million, of which $6.5 million was paid on emergence and $0.5 million included in accounts payable and accrued liabilities and paid in the subsequent month, as well as the write-off of a long-term leasehold improvement build-out receivable for $0.6 million relating to an office lease contract that was rejected in connection with the bankruptcy.

4. Reflects the settlement of predecessor accounts payable of $5.2 million partially offset by accrued debt issuance costs of $0.5 million.

5. Reflects the settlement of accrued interest on the Company's DIP Credit Agreement which was equitized upon emergence.

6. On the Effective Date, the Company repaid in full all borrowings outstanding of $289.5 million under the Prior First Lien Credit Facility. In addition the Company equitized the outstanding DIP Credit Agreement borrowings of $75 million via the issuance of equity valued at $142.3 million.

7. Reflects the $253 million in new borrowings under the New Credit Facility.

8. Liabilities subject to compromise were settled as follows in accordance with the Plan (in thousands):

7.125% senior notes due 2017	$	250,000
8.875% senior notes due 2020		225,000
7.875% senior notes due 2022		400,000
Accrued interest		30,043
Accounts payable and accrued liabilities		1,713
Other long-term liabilities		4,625
Liabilities subject to compromise of the Predecessor Company (LSTC)		911,381
Fair value of equity issued to former holders of the senior notes of the Predecessor		(47,443)
Gain on settlement of Liabilities subject to compromise	$	863,938

9. Reflects the cancellation of the Predecessor Company equity to retained earnings.

10. Reflects the issuance of 10.0 million shares of common stock at a per share price of $21.44 and 4.3 million warrants to purchase up to 30% of the reorganized Company's equity valued at $15.0 million with an average per unit value of $3.49. Former holders of the senior notes and certain unsecured creditors were issued 8.85 million shares of common stock while the Backstop

Lenders (as defined in the DIP Credit Agreement) were issued 0.75 million shares of common stock. Former shareholders received the warrants and 0.4 million shares of common stock.

11. Reflects the cumulative impact of the reorganization adjustments discussed above (in thousands):

Gain on settlement of Liabilities subject to compromise	$ 863,938
Fair value of equity issued in excess of DIP principal	(67,329)
Fair value of equity and warrants issued to Predecessor stockholders	(23,544)
Fair value of equity issued to DIP lenders for backstop fee	(16,082)
Other reorganization adjustments	(1,800)
Cancellation of Predecessor Company equity	775,429
Net impact to accumulated deficit	$ 1,530,612

Fresh Start Adjustments

12. The following table summarizes the fair value adjustment on our oil and gas properties and accumulated depletion, depreciation and amortization (in thousands):

	Predecessor Company	Fresh Start Adjustments	Successor Company
Oil and Gas Properties			
Proved properties	$ 5,951,016	$ (5,441,655)	$ 509,361
Unproved properties	12,057	33,448	45,505
Total Oil and Gas Properties	5,963,073	(5,408,207)	554,866
Less - Accumulated depletion and impairments	(5,638,741)	5,638,741	—
Net Oil and Gas Properties	324,332	230,534	554,866
Furniture, Fixtures, and other equipment	44,252	(40,551)	3,701
Less - Accumulated depreciation	(37,510)	37,510	—
Net Furniture, Fixtures and other equipment	$ 6,742	$ (3,041)	$ 3,701
Net Oil and Gas Properties, Furniture and fixtures and accumulated depreciation	$ 331,074	$ 227,493	$ 558,567

13. Reflects the adjustment of other non-current assets to fair value.

14. Reflects the current and long-term portion of the Company's asset retirement obligation computed in accordance with ASC 410-20, applying the appropriate discount rate to future costs as of the emergence date.

15. Reflects the adjustment of other non-current liabilities to fair value.

16. Reflects the cumulative impact of fresh start adjustments as discussed above.

Reorganization Items

Reorganization items represent liabilities settled, net of amounts incurred subsequent to the Chapter 11 filing as a direct result of the Plan and are classified as "(Gain) Loss on Reorganization items, net" in the Consolidated Statements of Operations. The following table summarizes reorganization items (in thousands):

	Successor	Predecessor	Predecessor
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	December 31, 2015
Gain on settlement of liabilities subject to compromise	$ —	$ (863,938)	$ —
Fair value of equity issued in excess of DIP principal	—	67,329	—
Fresh start adjustments	—	(222,512)	—
Reorganization legal and professional fees and expenses	1,598	25,573	—
Fair value of equity issued to DIP lenders for backstop fee	—	16,082	—
Write-off of debt issuance costs, including premium and discount on senior notes	—	—	6,565
Other reorganization items	41	21,324	—
(Gain) Loss on Reorganization items, net	$ 1,639	$ (956,142)	$ 6,565

2. Summary of Significant Accounting Policies

Fresh Start Accounting. Upon emergence from bankruptcy the Company adopted Fresh Start Accounting, see Note 1B for further details.

Basis of Presentation. The consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy," the "Company," or "we") assuming the Company will continue as a going concern, and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation.

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 oil and natural gas reserves in the Eagle Ford trend in 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 requiring potential accrual or disclosure in our consolidated financial statements. Effective January 25, 2017 the Company entered into an agreement to sell approximately 1.4 million shares of its Common Stock in a private placement at a price of $28.50 per share, which resulted in approximately $40.0 million in gross proceeds. The shares were sold to select institutional accredited investors and proceeds were primarily used to repay credit facility borrowings. Effective January 26, 2017 our borrowing base was reduced from $320 million, allocated between a non-conforming borrowing base of $70 million and conforming borrowing base of $250 million, to a fully conforming borrowing base of $250 million. See Note 5 for more information. 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 estimates of reorganization value, enterprise value and fair value of assets and liabilities upon emergence from bankruptcy and application of fresh start accounting,
- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows there-from, and the ceiling test impairment calculation,
- 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 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,
- estimates in the assessment of current litigation claims against the Company, and
- estimates in amounts due with respect to open state regulatory audits.

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 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. 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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor), and the years ended December 31, 2015 and 2014 (predecessor), such internal costs capitalized totaled $5.4 million, $2.9 million, $12.7 million and $26.3 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 5 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)	Successor December 31, 2016	Predecessor December 31, 2015
Property and Equipment		
Proved oil and gas properties	$ 480,499	$ 5,972,666
Unproved oil and gas properties	33,354	18,839
Furniture, fixtures, and other equipment	3,221	44,252
Less – Accumulated depreciation, depletion, amortization and impairment	(169,879)	(5,577,854)
Property and Equipment, Net	$ 347,195	$ 457,903

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.

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 estimated 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. 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.

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) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including estimated 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").

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.

Primarily due to pricing differences between the 12-month average oil and gas prices used in the Ceiling Test and the forward strip prices used to estimate the initial fair value of oil and gas properties on the Company's April 22, 2016 (successor) balance sheet, we incurred a non-cash impairment write-down during the period of April 23, 2016 through December 31, 2016 (successor) of $133.5 million. The full amount of this write-down was incurred as of June 30, 2016. Write-downs in prior periods were primarily the result of declining historical prices along with timing changes and reduction of projects and changes in our reserves product mix. For the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended 2015 and 2014 (predecessor) we reported non-cash impairment write-downs on a before-tax basis of $77.7 million, $1.6 billion and $445.4 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) if oil or natural gas prices decline, it is likely that non-cash write-downs of our oil and natural gas properties will 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, 2016 and 2015, we did not have any material natural gas imbalances.

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, 2016 and 2015, we had an allowance for doubtful accounts of less than $0.1 million and 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, 2016, our “Accounts receivable” balance included $12.6 million for oil and gas sales, $2.7 million for joint interest owners, $1.6 million for severance tax credit receivables and $0.6 million for other receivables. At December 31, 2015, our “Accounts receivable” balance included $14.9 million for oil and gas sales, $4.9 million for joint interest owners, $1.2 million for severance tax credit receivables and $0.7 million for other receivables.

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 allocated to each well based on general and administrative costs incurred for well maintenance and support. The amount of supervision fees charged for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor) did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $4.5 million and $2.7 million for the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively, and $9.2 million and $12.7 million for the years ended December 31, 2015 and 2014 (predecessor), 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 $0.4 million and $0.6 million at December 31, 2016 and 2015, respectively. During the year ended December 31, 2015, we recorded a charge of $2.0 million, related to inventory obsolescence in "Price-risk management and other, net" on the accompanying consolidated statement of operations.

Also included in "Other current assets" on the accompanying consolidated balance sheets are prepaid expenses totaling $2.0 million and $4.4 million at December 31, 2016 and 2015, respectively. These prepaid amounts cover well insurance, drilling contracts and various other prepaid expenses. In 2015 we also recorded $2.4 million in "Other current assets" related to a deposit received from Texegy as part of a purchase and sale agreement to sell a participating working interest of the Company's position in the South Bearhead Creek and Burr Ferry Field in central Louisiana. This amount was restricted until the transaction closed which occurred prior to our emergence from bankruptcy on April 22, 2016. Finally, as a result of the Company's bankruptcy proceedings, we reclassified $3.3 million in debt issuance costs related to our revolving credit facility as of December 31, 2015 from "Other Long-Term Assets" to "Other current assets". Debt issuance costs incurred on our New Credit Facility in 2016 were recorded in "Other Long-Term Assets" as of December 31, 2016.

Income Taxes. 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.

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. At December 31, 2016, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

The Company has evaluated the full impact of the reorganization on our carryover tax attributes and believes it will not incur an immediate cash income tax liability as a result of emergence from bankruptcy. The Company will be able to fully absorb cancellation of debt income with NOL carryforwards. The amount of remaining NOL carryforward available will be limited under IRC Sec. 382 due to the change in control. The Company’s amortizable tax basis exceeded the book carrying value of its assets at April 22 and December 31, 2016, leaving the Company in a net deferred tax asset position. Management has determined that it is not more likely than not that the Company will realize future cash benefits from this additional tax basis and remaining carryover items and accordingly has taken a full valuation allowance to offset its tax assets.

The Company expects to incur a net taxable loss in the current taxable period thus no current income taxes are anticipated to be paid and no benefit will be recorded due to the full valuation allowance on the tax assets.

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

	Successor December 31, 2016	Predecessor December 31, 2015
Trade accounts payable [(1)]	$ 10,563	$ —
Accrued operating expenses [(1)]	2,990	—
Accrued compensation costs [(1)]	4,730	—
Asset retirement obligations – current portion	9,965	7,165
Accrued non-income based taxes [(1)]	3,937	—
Accrued price risk management liabilities	17,632	—
Accrued corporate and legal fees [(1)]	3,075	—
Other payables [(1)(2)]	3,365	498
Total Accounts payable and accrued liabilities	$ 56,257	$ 7,663

(1) Classified as Liabilities Subject to Compromise as of December 31, 2015. Total Liabilities subject to compromise were $984.4 million as of December 31, 2015.
(2) Total balance at December 31, 2015 was $5.3 million of which $4.8 million was classified as Liabilities Subject to Compromise with the remaining portion classified as "Other payables".

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

Recognition of Severance Expense for Executive Retirements. On August 9, 2016, the Company announced that the Chief Executive Officer and Chief Financial Officer for the Company would be retiring. In the third quarter of 2016 we accrued $2.1 million for severance payments that will be paid out in accordance with their employment agreement. This amount was expensed in "General and administrative, net" in the consolidated statement of operations for the period of April 23, 2016 through December 31, 2016 (successor). Additionally we accelerated expense related to the equity awards held by the retiring Chief Executive Officer and Chief Financial Officer. See Note 8 for more details.

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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), Shell Oil Company and affiliates accounted for 15%, 19%, 16% and 21%, respectively of our sales proceeds, Kinder Morgan accounted for approximately 38%, 20%, 27% and 20%, respectively, of our sales proceeds and Plains Marketing accounted for approximately 14%, 14%, 18% and 11%, respectively, of our sales proceeds. Howard Energy accounted for approximately 11% and 13% of our sales proceeds during the period of January 1, 2016 through April 22, 2016 (predecessor) and year ended December 31, 2015 (predecessor). Southcross Energy accounted for approximately 11% of our sales proceeds during the period of January 1, 2016 through April 22, 2016 (predecessor).

Treasury Stock. Our treasury stock repurchases are reported at cost and are included in "Treasury stock held, at cost" on the accompanying consolidated balance sheets. When the Company reissues treasury stock the gains are recorded in "Additional paid-in capital" ("APIC") on the accompanying consolidated balance sheets, while the losses are recorded to APIC to the extent that previous net gains on the reissuance of treasury stock are available to offset the losses. If the loss is larger than the previous gains available then the loss is recorded to "Retained earnings (Accumulated deficit)" on the accompanying consolidated balance sheets. For the year ended December 31, 2015 (predecessor), the Company recorded losses of $4.9 million to "Retained earnings (Accumulated deficit)" as a result of treasury stock transactions. All treasury stock was canceled upon emergence from bankruptcy for the Predecessor Company. For the period of April 23, 2016 through December 31, 2016 (successor), 22,485 treasury shares were purchased in connection with the retirement of the former Chief Executive Officer and future retirement of the Chief Financial Officer.

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 requires entities 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, at the option of the Company, in retrospective application, either in the form of recasting all prior periods presented or a cumulative adjustment to equity in the period of adoption. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017.

The Company's revenues are virtually all attributable to oil and gas sales. Based on our initial review of our contracts, the Company believes the timing and presentation of revenues under ASU 2014-09 will be consistent with our current revenue recognition policy as described above with one probable exception. The Company currently uses the entitlement method of accounting when sales for our account are not in proportion to ownership interest in production. To comply with ASU 2014-09, the Company expects to recognize revenue on the production sold for our account irrespective of ownership share of such production. Currently we do not have any significant imbalance situations; therefore, this is not expected to immediately impact our financial statements. The Company will continue to monitor specific developments for our industry as it relates to ASU 2014-09.

In August 2014, the FASB issued ASU 2014-15, which provides guidance on determining when and how to disclose going-concern uncertainties in the financial statements. The new standard requires management to perform interim and annual assessments of an entity's ability to continue as a going concern within one year of the date the financial statements are issued. The guidance applies to all entities and is effective for annual periods ending after December 15, 2016, and interim periods thereafter. We implemented procedures to comply with this guidance as of December 31, 2016. Adoption of this standard had no impact on our financial statements.

In February 2016, the FASB issued ASU 2016-02, which requires lessees to record most leases on the balance sheet. Under the new guidance, lease classification as either a finance lease or an operating lease will determine how lease-related revenue and expense are recognized. The guidance is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.

At December 31, 2016 the Company had lease commitments of approximately $8.8 million that it believes would be subject to capitalization under ASU 2016-02. This includes $1.9 million for our new corporate office sub-lease which has a term of 4.4 years and commitments for equipment and vehicle leases which total $6.5 million. These equipment leases generally have original terms of 2 to 3 years. In some instances further analysis is needed to determine if renewal options would result in capitalized amounts in excess of the obligations during the primary lease term. Based on our preliminary assessment, we believe these leases would most likely be deemed to be operating leases under the new standard. The corporate office lease is the only existing lease that extends beyond December 31, 2018. Management plans to adopt ASU 2016-02 in the quarter ending March 31, 2019. Management continuously evaluates the economics of leasing vs. purchase for operating equipment. The lease obligations that will be in place upon adoption of ASU 2016-02 may be significantly different than the current obligations. Accordingly, at this time we cannot estimate the amount that will be capitalized when this standard is adopted.

In March 2016, the FASB issued ASU 2016-09, which simplifies several aspects of the accounting for employee share based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The guidance is effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years, with early adoption permitted. This standard was adopted by the Company as of the bankruptcy emergence date April 22, 2016. The adoption of this guidance did not result in any adjustments.

In August 2016, the FASB issued ASU 2016-15, which provides greater clarity to preparers on the treatment of eight specific items within an entity's statement of cash flows with the goal of reducing existing diversity on these items. The guidance is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the ASU in an interim period, adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity that elects early adoption must adopt all of the amendments in the same period. We are currently reviewing these new requirements to determine the impact of this guidance on our financial statements.

3. Earnings Per Share

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 1A, the Company's then outstanding common stock was canceled and new common stock and warrants were issued.

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 have been 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 period of April 23, 2016 through December 31, 2016 (successor) and the years ended 2015 and 2014 (predecessor), the unvested share-based payments and stock options were not recognized in the Diluted EPS calculations as they would be antidilutive. Certain stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the period of January 1, 2016 through April 22, 2016 (predecessor), 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 period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended 2015 and 2014 (predecessor) (in thousands, except per share amounts):

	Successor from April 23, 2016 through December 31, 2016			Predecessor from January 1, 2016 through April 22, 2016		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ (156,288)	10,013	$ (15.61)	$ 851,611	44,692	$ 19.06
Dilutive Securities:						
Restricted Stock Awards		—			1,005	
Restricted Stock Units Awards		—			—	
Stock Option Awards		—			—	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$ (156,288)	10,013	$ (15.61)	$ 851,611	45,697	$ 18.64

	Predecessor 2015			Predecessor 2014		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ (1,653,971)	44,463	$ (37.20)	$ (283,427)	43,795	$ (6.47)
Dilutive Securities:						
Restricted Stock Awards		—			—	
Restricted Stock Unit Awards		—			—	
Stock Option Awards		—			—	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$ (1,653,971)	44,463	$ (37.20)	$ (283,427)	43,795	$ (6.47)

Approximately 0.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the period of April 23, 2016 through December 31, 2016 (successor), because these stock options were antidilutive. Approximately 1.3 million stock options to purchase shares were not included in the computation of Diluted EPS for the period of January 1, 2016 through April 22, 2016 (predecessor), because the exercise price was out of the money, while 1.3 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2015 and 2014 (predecessor), respectively, as they were antidilutive.

Approximately 0.3 million restricted stock awards for the period of January 1, 2016 through April 22, 2016 (predecessor), and 0.5 million restricted stock awards for the years ended December 31, 2015 and 2014, respectively, were not included in the computation of Diluted EPS because they were antidilutive.

Approximately 0.2 million shares related to restricted stock units for the period of April 23, 2016 through December 31, 2016 (successor) were not included in the computation of Diluted EPS because these stock awards were antidilutive. Approximately 0.8 million shares for the period of January 1, 2016 through April 22, 2016 (predecessor) and 0.6 million and 0.4 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, 2015 and 2014 (predecessor), 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.

Upon the Company's emergence from bankruptcy on April 22, 2016, the Company issued 2019 and 2020 warrants (as previously discussed in Note 1B of these consolidated financial statements). They were not included in the computation of Diluted EPS for the period of April 23, 2016 through December 31, 2016, as they were antidilutive.

4. Provision (Benefit) for Income Taxes

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

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Income (Loss) Before Income Taxes	$ (156,288)	$ 851,611	$ (1,734,514)	$ (433,470)

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

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Current	$ —	$ —	$ (410)	$ 314
Deferred	—	—	(80,133)	(150,357)
Total	**$ —**	**$ —**	**$ (80,543)**	**$ (150,043)**

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

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Federal Statutory Rate	35.0 %	35.0 %	35.0 %	35.0 %
State tax provisions (benefits), net of federal benefits	0.9 %	0.9 %	1.0 %	1.4 %
Reorganization Adjustments	— %	(1.8)%	— %	— %
Expiration/Write-off of NOL Carryovers	(74.9)%	— %	— %	(0.1)%
Valuation allowance adjustments	38.9 %	(35.1)%	(31.3)%	(1.1)%
Other, net	0.2 %	1.0 %	(0.1)%	(0.7)%
Effective rate	— %	— %	4.6 %	34.5 %

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2016 and 2015 were as follows (in thousands):

	Successor	Predecessor
	Year Ended December 31, 2016	Year Ended December 31, 2015
Deferred tax assets:		
Federal net operating loss ("NOL") carryovers	$ 40,104	$ 287,720
NOLs for excess stock-based compensation	—	(9,571)
Oil and gas exploration and development costs	71,292	214,413
State NOL carryovers	—	18,384
Alternative minimum tax credits	2,092	2,092
Other Carryover Items	1,107	1,215
Asset Retirement Obligations	11,447	22,884
Derivative Contracts	5,802	—
Unrealized share-based compensation	648	9,953
Valuation allowance	(136,656)	(553,283)
Other	4,164	6,193
Total deferred tax assets	**$ —**	**$ —**
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ —	$ —
Other	—	—
Total deferred tax liabilities	**$ —**	**$ —**
Net deferred tax liabilities	$ —	$ —
Net current deferred tax assets	—	—
Net non-current deferred tax liabilities	$ —	$ —

The Company has evaluated the full impact of the reorganization on our carryover tax attributes and believes it will not incur an immediate cash income tax liability as a result of emergence from bankruptcy. The Company will be able to fully absorb cancellation of debt income (CODI), estimated to be $854 million, with NOL carryforwards. The remaining NOL carryforward will be severely limited under Sec. 382 due to the change in control annual limitation of $5.8 million. The NOL carryforward that will expire before utilization due to the IRC Sec. 382 limitation is estimated to be $305 million. The deferred tax asset associated with the NOLs expected to expire was written off as of December 31, 2016. The remaining NOL carryforward after CODI and excess Sec. 382 limitation is $115 million, which will expire between 2034 and 2035 if not utilized in earlier periods. The Company's state NOL carryforwards and deferred tax benefits for excess stock-based compensation deductions were written off as part of the reorganization.

The Company's amortizable tax basis exceeded the book carrying value of its assets at December 31, 2016 and December 31, 2015, leaving the Company in a net deferred tax asset position. Management has determined that it is not more likely than not that the Company will realize future cash benefits from this additional tax basis and remaining carryover items and accordingly has recorded a full valuation allowance to offset its tax assets. The Company's valuation allowance balance was $137 million and $553 million at December 31, 2016 and December 31, 2015, respectively.

As of December 31, 2016, 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.

The Company records interest and penalties related to potential underpayment of any unrecognized tax benefits as a component of income tax expense. The Company has not incurred any interest or penalties associated with unrecognized tax benefits.

Our U.S. federal and state income tax returns from 2015 forward are subject to examination. For years prior to 2015 our U.S federal and state returns are subject to examination to the extent of our net operating loss (NOL) carryforwards. There are no material unresolved items related to periods previously audited by these taxing authorities.

5. Long-Term Debt

Bankruptcy Filing. The Chapter 11 filing of the Company and the Chapter 11 Subsidiaries constituted an event of default with respect to our then-existing debt obligations. As a result, the Company's pre-petition unsecured senior notes and secured debt under the Prior First Lien Credit Facility became immediately due and payable, but any efforts to enforce such payment obligations were automatically stayed as a result of the Chapter 11 filing. On April 22, 2016, upon the Company's emergence from bankruptcy, the senior notes and borrowing under the DIP Credit Agreement (along with certain unsecured claims) were exchanged for 88.5% of the common stock of the reorganized entity. Additional information regarding the bankruptcy proceedings is included in Note 1A of the consolidated financial statements.

Our debt balances as of December 31, 2016 and 2015, were as follows (in thousands):

	Successor December 31, 2016	Predecessor December 31, 2015
7.125% senior notes due in 2017 (1)	—	—
8.875% senior notes due in 2020 (1)	—	—
7.875% senior notes due in 2022 (1)	—	—
Bank Borrowings	$ 198,000	$ 324,900
Total Debt	198,000	324,900
Less: Current portion of long-term debt (2)	$ —	$ (324,900)
Long-Term Debt	$ 198,000	$ —

(1) Classified as Liabilities Subject to Compromise as of December 31, 2015

(2) As a result of our Chapter 11 filing, we classified our credit facility borrowings as current at December 31, 2015.

New Credit Facility. As discussed in Note 1A of these consolidated financial statements, on the Effective Date, the Prior First Lien Credit Facility was terminated and paid in full, and the Company entered the New Credit Facility among the Company, as borrower, JPMorgan Chase Bank, National Association, as administrative agent, and certain lenders party thereto. The New Credit Facility matures on April 22, 2019 and provides for advancing loans of up to the maximum credit amount that the lenders, in the aggregate, make available, subject to the Company meeting certain financial requirements, including certain financial tests. As of the Effective Date, the maximum credit amount was $500.0 million with an initial borrowing base of $320.0 million. The obligations under the New Credit Facility are secured, subject to certain exceptions, by a first priority lien of the Company's, and certain of its subsidiaries, oil and natural gas properties containing at least 95% of the Company's estimated proved producing reserves. The terms of the New Credit Facility also include the following, based on terms as defined in the New Credit Facility agreement:

- As of the Effective Date and through December 31, 2016 , the initial borrowing base of $320.0 million was allocated between a non-conforming borrowing base of $70.0 million which was originally scheduled to terminate on November 1, 2017, and a conforming borrowing base of $250.0 million. Effective January 26, 2017 the Company and the lenders agreed to terminate the non-conforming borrowing base leaving only the conforming borrowing base of $250.0 million. As of December 31, 2016, the Company had borrowings of $198.0 million drawn on the credit facility.
- Borrowing base redeterminations are scheduled to occur semi-annually in November and May and are determined by the lenders in their discretion and in the usual and customary manner.
- The interest rate for Alternative Base Rate ("ABR") loans will be based on the ABR plus the applicable margin, and the interest rate for Eurodollar loans will be based on the adjusted London Interbank Offered Rate (“LIBOR”), plus the applicable margin.
- As of December 31, 2016, the applicable margins varied and had escalating rates of either (a) 500 to 600 basis points for ABR loans and 600 to 700 basis points for Eurodollar loans, during the non-conforming period, and depending on the level of the non-conforming borrowing base and the non-conforming borrowing base loans outstanding, or (b) 200 to 300 basis points for ABR loans and 300 to 400 basis points for Eurodollar loans depending on the borrowing base utilization percentage, after the non-conforming period or when the non-conforming borrowing base is zero. Given the termination of the non-conforming borrowing base effective January 26, 2017, the applicable margins going forward are

200 to 300 basis points for ABR loans and 300 to 400 basis points for Eurodollar loans. As of December 31, 2016, our average borrowing rate was 7.9%.

- Certain covenants, including (a) a ratio of total debt to EBITDA (as defined in the agreement) not to exceed 6.0 to 1.0 for the quarter ending December 31, 2016, declining gradually over time to 3.5 to 1.0 for the quarter ending March 31, 2019, and thereafter, (b) a current ratio of not less than 1.0 to 1.0 and (c) a minimum liquidity requirement of $10.0 million. As of December 31, 2016, the Company was in compliance with these covenants and liquidity requirements.

Interest expense on the New Credit Facility, including commitment fees and amortization of debt issuance costs, totaled $15.3 million for the period of April 23, 2016 through December 31, 2016 (successor). The amount of commitment fees amortization included in interest expense, net was $0.2 million for the period of April 23, 2016 through December 31, 2016 (successor).

Additionally, we capitalized interest on our unproved properties in the amount of $0.5 million for the period of April 23, 2016 through December 31, 2016 (successor).

Debtor-In-Possession Financing. As part of the Chapter 11 filings, we entered into the DIP Credit Agreement. The proceeds of borrowings under the DIP Credit Agreement were primarily used to pay down the pre-petition Prior First Lien Credit Facility upon emergence from bankruptcy, and were also used to pay certain costs, fees and expenses related to the Chapter 11 cases, authorized pre-petition claims, and amounts due in connection with the DIP Credit Agreement, including on account of certain "adequate protection" obligations. Pursuant to the Plan, the DIP Credit Agreement, at the option of the lenders, converted into the post-emergence Company's common stock, which was part of the 88.5% of the common stock distributed to the then current holders of the senior notes and certain unsecured creditors upon emergence from the bankruptcy proceedings. As a result, the $75.0 million borrowed under the DIP Credit Agreement was not required to be repaid and the DIP Credit Agreement was terminated upon the Company's exit from bankruptcy.

We paid the lenders under the DIP Credit Agreement a 3.0% commitment fee, at the time funds were made available under the facility, totaling $0.9 million. The commitment fee was included in interest expense during the period of January 1, 2016 through April 22, 2016 (predecessor). Total interest expense on the DIP Credit Agreement was $6.4 million during the period of January 1, 2016 through April 22, 2016 (predecessor).

Prior First Lien Credit Facility Bank Borrowings. Amounts outstanding under our pre-petition Prior First Lien Credit Facility due in 2017 of $324.9 million were classified as a current liability in the Consolidated Balance Sheet dated as of December 31, 2015 due to cross-default provisions as a result of the bankruptcy filings. The interest rate on our Prior First Lien Credit Facility was 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 was 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 then applied. The applicable margins varied depending on the level of outstanding debt with escalating rates of 100 to 200 basis points above the Alternative Base Rate and escalating rates of 200 to 300 basis points for Eurodollar rate loans. The commitment fee terms associated with the Prior First Lien Credit Facility were 0.50%. During the bankruptcy proceedings we paid interest on our Prior First Lien Credit Facility in the normal course.

Interest expense on the Prior First Lien Credit Facility, including commitment fees and amortization of debt issuance costs, totaled $6.8 million, $9.4 million and $7.5 million for the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), respectively. The amount of commitment fees included in interest expense, net was not material for the period of January 1, 2016 through April 22, 2016 (predecessor) and $0.5 million and $0.8 million for the years ended December 31, 2015 and 2014 (predecessor), respectively.

Additionally, we have capitalized interest on our unproved properties in the amount of $4.9 million and $5.0 million for the years ended December 31, 2015 and 2014 (predecessor), respectively. Capitalized interest on our unproved properties would have been immaterial for the period of January 1, 2016 through April 22, 2016 (predecessor), and therefore we did not capitalize any interest.

Senior Notes Liabilities. Senior Notes due in 2017 of $250.0 million, Senior Notes due in 2020 of $225.0 million and Senior Notes due in 2022 of $400.0 million are included in Liabilities subject to compromise in the Consolidated Balance Sheet as of December 31, 2015. These notes were canceled upon emergence from bankruptcy.

Senior Notes Due In 2022. These notes consist of $400.0 million of 7.875% senior notes that were scheduled to mature on March 1, 2022. The filing of the petition for bankruptcy protection constituted an "event of default" under the indenture governing these senior notes. On April 22, 2016, the obligations of the Company and the Chapter 11 Subsidiaries with respect to these notes were canceled pursuant to the plan of reorganization and the holders thereof were issued common stock of the post-emergence entity in exchange therefor.

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 filing of the petition for bankruptcy protection constituted an “event of default” under the indenture governing these senior notes. On April 22, 2016, the obligations of the Company and the Chapter 11 Subsidiaries with respect to these notes were canceled pursuant to the plan of reorganization and the holders thereof were issued common stock of the post-emergence entity in exchange therefor.

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 were scheduled to mature on June 1, 2017. The filing of the petition for bankruptcy protection constituted an “event of default” under the indenture governing these senior notes. On April 22, 2016, the obligations of the Company and the Chapter 11 Subsidiaries with respect to these notes were canceled pursuant to the plan of reorganization and the holders thereof were issued common stock of the post-emergence entity in exchange therefor.

Debt Issuance Costs. Our policy is to capitalize legal fees, accounting fees, underwriting fees, printing costs, and other direct expenses associated with issuing debt. The costs associated with our senior notes were amortized on an effective interest basis over the term of the senior notes, while issuance costs related to our line of credit arrangement are capitalized and then amortized ratably over the term of the line of credit arrangement, regardless of whether there are any outstanding borrowings.

Interest Expense on Senior Notes. There was no interest expense on the senior notes, for the period of January 1, 2016 through April 22, 2016 (predecessor) due to bankruptcy proceedings. Contractual interest on the senior notes for the period of January 1, 2016 through April 22, 2016 (predecessor) totaled $21.6 million. Interest expense on the senior notes, including amortization of debt issuance costs, debt discount and debt premium, totaled $70.8 million and $70.7 million for the years ended December 31, 2015 and 2014 (predecessor), respectively.

6. Price-Risk Management Activities

Derivatives are recorded on the balance sheet at fair value with changes in fair value recognized in earnings. The changes in the fair value of our derivatives 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 swaps and collars.

For the period of April 23, 2016 through December 31, 2016 (successor) we recognized a $19.7 million loss relating to our derivative activities. For the years ended December 31, 2015 and 2014 (predecessor) we recognized a $0.2 million and $1.3 million gain, respectively. The Company made net cash payments of $1.9 million for settled derivative contracts during the period of April 23, 2016 through December 31, 2016 (successor). For the years ended December 31, 2015 and 2014 (predecessor) we received net cash payments of $2.5 million and made net cash payments of $1.1 million, respectively, for settled derivative contracts. There were no derivative instruments outstanding during the period of January 1, 2016 through April 22, 2016 (predecessor).

At December 31, 2016 we had $0.4 million in receivables for settled derivatives which were recognized on the accompanying consolidated balance sheet in “Accounts receivable” and were subsequently collected in January 2017. At December 31, 2016 we had $1.8 million in payables for settled derivatives which were recognized on the accompanying consolidated balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in January 2017.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. At December 31, 2016 there was $0.5 million in current unsettled derivative assets, while our long-term unsettled derivative assets were not material. At December 31, 2016 there was $15.8 million and $1.0 million in current and long-term unsettled derivative liabilities, respectively.

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 does not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. Under the right of set-off, there was a $16.4 million net fair value liability at December 31, 2016. For further discussion related to the fair value of the Company's derivatives, refer to Note 11 of these consolidated financial statements.

The following table summarizes the weighted average prices as well as future production volumes for our unsettled derivative contracts in place as of December 31, 2016.

Oil Derivative Swaps (NYMEX WTI Settlements)	Total Volumes (Bbls)	Weighted Average Price
2017 Contracts		
1Q17	106,245	$ 48.04
2Q17	97,401	$ 48.13
3Q17	90,000	$ 48.16
4Q17	84,798	$ 48.18

Natural Gas Derivative Contracts (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Weighted Average Swap Price	Weighted Average Collar Floor Price	Weighted Average Collar Call Price
Swap Contracts				
1Q18	4,395,000	$ 3.47		
1Q17	4,500,000	$ 3.13		
2Q17	5,420,005	$ 2.96		
3Q17	5,104,999	$ 2.98		
4Q17	3,725,001	$ 2.92		
Collar Contracts				
1Q17	550,000		$ 3.300	$ 3.900
2Q17	2,400,000		$ 3.050	$ 3.545
3Q17	2,865,000		$ 3.050	$ 3.585
4Q17	3,102,000		$ 3.100	$ 3.715

Natural Gas Basis Derivative Swaps (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Weighted Average Price
2018 Contracts		
1Q18	1,500,000	$ (0.08)
2017 Contracts		
1Q17	5,050,000	$ (0.08)
2Q17	7,820,005	$ (0.03)
3Q17	7,969,999	$ (0.02)
4Q17	6,827,001	$ (0.04)

7. Commitments and Contingencies

Rental and lease expenses were $5.7 million, $4.5 million, $16.8 million and $21.0 million for the period of April 23, 2016 through December 31, 2016 (successor), period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), respectively. The rental and lease expenses primarily relate to compressor rentals and the lease of our office space in Houston, Texas. During 2016 the Company entered into a new four year sub-lease agreement for office space in Houston, Texas. The operating lease commenced on January 1, 2017. As of December 31, 2016, the minimum contractual obligations were approximately $1.9 million in the aggregate. Our policy is to amortize the total payments under the lease agreement on a straight-line basis over the term of the lease.

Our minimum annual obligations under non-cancelable operating lease commitments were $5.5 million for 2017, $2.0 million for 2018, $0.6 million for 2019, $0.5 million for 2020, $0.2 million for 2021 and approximately $8.8 million in the aggregate. The minimum annual obligations under non-cancelable operating lease commitments primarily relate to compressor rentals and office space for the Houston office.

We have gas transportation and processing minimum obligations amounting to $8.3 million for 2017, $13.5 million for 2018, $12.8 million for 2019, $10.8 million for 2020 and $45.4 million in the aggregate.

In the ordinary course of business, we are 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.

8. Share-Based Compensation

Emergence from Voluntary Reorganization

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 1A, the Company’s common stock was canceled and new common stock was issued. The Company's previous share-based compensation awards were either vested or canceled upon the Company's emergence from bankruptcy.

Share-Based Compensation Plans

Upon the Company's emergence from bankruptcy on April 22, 2016, the new Swift Energy Company 2016 Equity Incentive Plan was approved in accordance with the joint plan of reorganization. Under the previous share-based compensation plan the outstanding restricted stock awards and restricted stock unit awards for most employees vested on an accelerated basis while awards issued to certain officers of the Company and the Board of Directors were canceled.

For awards granted after emergence from bankruptcy, the Company does not estimate the forfeiture rate during the initial calculation of compensation cost but rather has elected to account for forfeitures in compensation cost when they occur. For the predecessor periods the Company had estimated the forfeiture rate for share-based compensation during the initial calculation of compensation cost.

The Company computes a deferred tax benefit for restricted stock awards, unit awards and stock options expected to generate future tax deductions by applying its effective tax rate to the expense recorded. For restricted stock units the Company's actual tax deduction is based on the value of the units at the time of vesting.

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.

For the period of April 23, 2016 through December 31, 2016 (successor), no incremental tax benefit was recognized for shares that vested due to the offsetting valuation allowance as discussed in Note 4 in our Form 10-K of these consolidated financial statements. For the period of January 1, 2016 through April 22, 2016 (predecessor) the tax deduction realized was significantly less than the associated deferred tax asset, however the tax asset had been fully offset with a valuation allowance in prior periods so no incremental tax expense was realized. For the years ended December 31, 2015 and 2014 (predecessor), we recognized an income tax shortfall in earnings as referenced in Note 4 of these consolidated financial statements.

Share-based compensation for the predecessor and successor periods are not comparable. The expense for awards issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying consolidated statements of operations was $3.6 million for the period of April 23, 2016 through December 31, 2016 (successor), while for the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor) the expense was $0.9 million, $4.1 million and $6.7 million, respectively.

We have not capitalized any share-based compensation for the period of April 23, 2016 through December 31, 2016 (successor). For the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor) we capitalized $0.2 million, $1.4 million and $3.5 million, respectively. We view stock option awards and restricted stock unit awards with graded vesting as single awards with an expected life equal to the average expected life of component awards, and we amortize the awards on a straight-line basis over the life of the awards.

Share-based compensation recorded in lease operating cost was $0.2 million for the years ended December 31, 2015 and 2014 (predecessor). There was no share-based compensation recorded in lease operating cost for the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through December 31, 2016 (successor).

Our shares available for future grant under our Share-Based Compensation plans were 221,295 at December 31, 2016. Each restricted stock award and restricted stock unit granted reduces the shares available for future grant by one share.

Stock Option Awards

On June 8, 2016, 105,811 stock option awards were granted to various officers and directors with an exercise price of $23.25. The compensation cost related to these awards is based on the grant date fair value and is expensed over the vesting period (generally one to three years). We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following assumptions for stock option awards issued during the period of April 23, 2016 through December 31, 2016 (successor):

	Stock Option Valuation Assumptions
Expected Dividend	—
Expected volatility	69.3%
Risk-free interest rate	1.42%
Expected life of stock option awards (in years)	4
Weighted average grant-date fair value	$ 12.64

To estimate expected volatility of our 2016 stock option grants we used the historical volatility of stock prices based on a group of our peer companies. The expected term for grants issued considers all relevant factors including historical and expected future employee exercise behavior. We have analyzed historical volatility and, based on an analysis of all relevant factors, we have used a 4 year look-back period to estimate expected volatility of our stock option awards.

At December 31, 2016, we had $0.4 million unrecognized compensation cost related to stock option awards. The following table represents stock option award activity for the year ended December 31, 2016:

	2016	
	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period (Predecessor)	1,330,390	$ 34.02
Options canceled/vested upon emergence from bankruptcy	(1,330,390)	$ —
Options outstanding, as of April 22, 2016 (Successor)	—	$ —
Options granted	105,811	$ 23.25
Options canceled	—	$ —
Options exercised	—	$ —
Options outstanding, end of period (Successor)	105,811	$ 23.25
Options exercisable, end of period (Successor)	60,847	$ 23.25

Our outstanding stock option awards at December 31, 2016 had $1.1 million aggregate intrinsic value. At December 31, 2016 the weighted average remaining contract life of stock option awards outstanding was 3.2 years and exercisable was 2.3 years. The total intrinsic value of stock option awards exercisable for the year ended December 31, 2016 was $0.6 million.

The following table summarizes information about stock option awards outstanding at December 31, 2016:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/16	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/16	Wtd. Avg. Exercise Price
$1.00 to $25.00	105,811	3.2	$ 23.25	60,874	$ 23.25

Restricted Stock Awards

The following table represents restricted stock award activity for the year ended December 31, 2016:

	2016	
	Shares	Wtd. Avg. Grant Price
Restricted awards outstanding, beginning of period (Predecessor)	1,487,076	$ 8.94
Restricted awards canceled/vested upon emergence from bankruptcy	(1,487,076)	$ 8.94
Restricted awards, as of April 22, 2016 (Successor)	$ —	$ —
Restricted shares outstanding, end of period (Successor)	—	$ —

Restricted Stock Units

The 2016 equity incentive compensation plan allows for the issuance of restricted stock unit awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The compensation cost related to these awards is based on the grant date fair value and is expensed over the requisite service period (generally one to three years).

On June 8, 2016, 254,905 restricted stock unit awards were granted to various officers and directors with a grant-date fair value of $23.25. These grants generally vest over a period of one to three years.

As of December 31, 2016, we had unrecognized compensation expense of $3.2 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.3 years.

The following table represents restricted stock unit activity for the year ended December 31, 2016:

	Shares	Wtd. Avg. Grant Price
Restricted units outstanding, beginning of period (Predecessor)	591,400	$ 9.20
Restricted units canceled/vested upon emergence from bankruptcy	(591,400)	$ 9.20
Restricted units, as of April 22, 2016 (Successor)	—	$ —
Restricted stock units granted	254,905	$ 23.25
Restricted stock units canceled	—	$ —
Restricted stock units vested	76,058	$ 23.25
Restricted stock units outstanding, end of period (Successor)	178,847	$ 23.25

In accordance with their employment agreements, the Chief Executive Officer and Chief Financial Officer vested in all of their share-based compensation awards in conjunction with their retirements. As such, all expense for their stock option awards and restricted stock unit awards was accelerated and is included in the share-based compensation expense for the period of April 23, 2016 through December 31, 2016 (successor). The total expense included in the period for such awards was $1.6 million for 76,058 restricted stock unit awards and $0.7 million for 60,847 stock option awards.

Employee Savings Plan

We have a savings plan under Section 401(k) of the Internal Revenue Code. For 2016 the Company contributed on behalf of the eligible employee an amount up to 100% of the first 2% of compensation based on the contributions made by the eligible employees. The Company's 2016 plan contribution of $0.3 million was paid in cash during the first quarter of 2017. The Company's contributions to the 401(k) savings plan were $0.7 million for the year ended December 31, 2015 and were $1.9 million for the year ended December 31, 2014. 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.

Predecessor Share-Based Compensation Awards

We previously had shares outstanding under multiple share-based compensation plans with outstanding awards including the 2005 Stock Compensation Plan, last 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. In addition, we had an employee stock purchase plan and also had an employee stock ownership plan prior to their termination during 2016 and 2015, respectively.

Under the 2005 plan, stock option awards and other equity-based awards could 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. Restricted stock grants became vested over a three year period, and stock option awards were exercisable in various terms ranging from one year to five years. Stock option awards granted typically expired 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 were exercised, the cash received was credited to common stock and additional paid-in capital.

The employee stock purchase plan, which began in 1993, provided eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. Under this plan, we had issued 87,629 shares at a price of $3.44 in 2015 and 71,825 shares at a price of $11.47 in 2014. As of December 31, 2015, this plan was terminated.

During the years ended December 31, 2015 and 2014, we did not grant any stock option awards and there were no stock option exercises for the years ended December 31, 2015 and 2014. The total intrinsic value of stock option awards exercised for the years ended December 31, 2015 and 2014 was not material.

For the years ended December 31, 2015 and 2014, the Company issued 609,238 shares and 747,400 shares, respectively, of restricted stock to employees, consultants, and directors. The weighted average fair values of these shares when issued, for the years ended December 31, 2015 and 2014 were $2.64 and $11.55 per share, respectively. The grant date fair values of shares vested for the years ended December 31, 2015 and 2014 were $6.1 million and $11.8 million, respectively. All of the remaining grants either vested or were canceled upon emergence from bankruptcy.

During the year ended 2015, the Company granted 147,812 units of cash-settled restricted stock units. The grants had a cliff vesting period of approximately 1.0 year while the compensation expense and corresponding liability were re-measured quarterly over the corresponding service period. All of the remaining grants were canceled upon emergence from bankruptcy.

For the years ended December 31, 2015 and 2014, the Company granted 216,450 and 185,250 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. No shares vested during the years ended December 31, 2015 and 2014. The weighted average grant date fair value for the restricted stock units granted during the years ended December 31, 2015 and 2014 was $1.98 and $11.68 per unit, respectively. All of the remaining grants were canceled upon emergence from bankruptcy.

9. Related-Party Transactions

We received 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 former Chairman of the Board and Chief Executive Officer. We paid Tec-Com, for services pursuant to the terms of the contract, approximately $0.5 million and $0.6 million for the years ended 2015 and 2014 (predecessor), respectively. The contract was terminated on March 31, 2016.

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.

10. Acquisitions and Dispositions

On April 15, 2016, we closed our transaction with Texegy LLC for the sale of a 75% working interest share of the Company's holdings in the South Bearhead Creek and Burr Ferry field areas located in Central Louisiana. The net proceeds of $46.9 million received by the Company in this transaction, including deposits received prior to the closing date, were credited to the full cost pool and used primarily to reduce the amount of borrowings under the Company’s Prior First Lien Credit Facility, and for other general corporate purposes. This disposition also included the buyer's assumption of approximately $6.5 million of plugging and abandonment liability. On December 8, 2016 we sold the remaining 25% working interest share of the Company's holdings in the South Bearhead Creek and Burr Ferry fields to Texegy. We received net proceeds of $7.1 million on the sale which were used to reduce the amount of borrowings under the Company's credit facility. This disposition also included the buyer's assumption of approximately $2.4 million of plugging and abandonment liability.

Effective April 25, 2016, we disposed of our Masters Creek field in Central Louisiana. We received net proceeds of less than $0.1 million and the buyer assumed approximately $8.1 million of plugging and abandonment liability.

Effective September 30, 2016, we closed our transaction with Blue Marble Resources LLC for the sale of the Company's holdings in our Sun TSH field located in South Texas. We received net proceeds of approximately $0.9 million and the buyer assumed approximately $1.8 million of plugging and abandonment liability.

On December 1, 2016, we closed our transaction with Hilcorp Energy I, L.P., effective September 1, 2016, for the sale of the Company's holdings in our Lake Washington field located in South East Louisiana. We received net proceeds of approximately $37.0 million which were used to reduce the amount of borrowings under the Company's credit facility. The buyer assumed approximately $30.5 million of plugging and abandonment liability.

Effective December 16, 2016, we sold an overriding royalty package in the Barnett Shale area for $0.5 million to San Saba Royalty Company.

In accordance with our Full Cost Accounting policy, no gains or losses were recognized on these disposition transactions. The sales proceeds were credited to our proved oil and gas property accounts.

11. Fair Value Measurements

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, restricted cash, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments.

The carrying amount of the revolving long-term debt approximates fair value because the Company's current borrowing base rate does not materially differ from market rates for similar bank borrowings.

Based upon quoted market prices as of December 31, 2015 (predecessor), the fair value and carrying value of our senior notes was as follows (in millions):

	Predecessor	
	Subject to Compromise	
	December 31, 2015	
	Fair Value	Carrying [(1)] Value
7.125% senior notes due in 2017	$ 23.0	$ 250.0
8.875% senior notes due in 2020	$ 21.4	$ 225.0
7.875% senior notes due in 2022	$ 34.5	$ 400.0

(1) Includes write-off of discount associated with the 2020 notes and premium associated with the 2022 notes due to the Company's bankruptcy proceedings.

Our senior notes due in 2017, 2020 and 2022 were stated at carrying value on our accompanying consolidated balance sheets until they were canceled as part of the Company's plan of reorganization and emergence from bankruptcy. If we recorded these notes at fair value they would have been Level 1 in our fair value hierarchy as they were traded in an active market with quoted prices for identical instruments until they were canceled.

The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (table below in millions):

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.

The following table presents our assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2016 for the Successor Company, and are categorized using the fair value hierarchy. As of December 31, 2015 all of the Predecessor Company's hedging agreements had settled. For additional discussion related to the fair value of the Company's derivatives, refer to Note 6 of these consolidated financial statements.

	Fair Value Measurements at			
(in millions)	Total	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2016				
Assets				
Natural Gas Basis Derivatives	$ 0.4	$ —	$ 0.4	$ —
Liabilities				
Natural Gas Derivatives	$ 13.7	$ —	$ 13.7	$ —
Natural Gas Basis Derivatives	$ 0.1	$ —	$ 0.1	$ —
Oil Derivatives	$ 3.0	$ —	$ 3.0	$ —

Our current and long-term unsettled 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”, "Other long-term assets", "Accounts payable and accrued liabilities" and "Other long-term liabilities", respectively.

12. Asset Retirement Obligations

Liabilities for legal obligations associated with the retirement obligations of tangible long-lived assets are initially recorded at fair value in the period in which they are incurred. When a 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 DD&A 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 recorded to the “Property and Equipment” balance on our accompanying consolidated balance sheets.

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 1A, the Company applied fresh start accounting. This included adjusting the Asset Retirement Obligations based on the estimated fair values at April 22, 2016.

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

Asset Retirement Obligations as of December 31, 2014	**$**	**72,831**
Accretion expense		5,572
Liabilities incurred for new wells and facilities construction		151
Reductions due to sold and abandoned wells and facilities		(4,576)
Revisions in estimates		(10,423)
Asset Retirement Obligations as of December 31, 2015	**$**	**63,555**
Accretion expense		1,610
Liabilities incurred for new wells and facilities construction		1
Reductions due to sold wells and facilities		(6,545)
Reductions due to plugged wells and facilities		(85)
Revisions in estimates		488
Asset Retirement Obligations as of April 22, 2016 (Predecessor)	**$**	**59,024**
Fair value fresh start adjustment		5,216
Asset Retirement Obligation as of April 22, 2016 (Successor)	**$**	**64,240**
Accretion expense		2,878
Liabilities incurred for new wells and facilities construction		34
Reductions due to sold wells and facilities		(42,857)
Reductions due to plugged wells and facilities		(916)
Revisions in estimates		8,877
Asset Retirement Obligations as of December 31, 2016 (Successor)	**$**	**32,256**

At December 31, 2016 and 2015, approximately $10.0 million and $7.2 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. The 2016 revisions in estimates are primarily attributable to revaluation changes in our Bay De Chene field and a portion of our South Texas AWP field, which led to an increase in the estimated plugging and abandonment costs for our wells.

Supplementary Information (unaudited)

Swift Energy Company and Subsidiaries
Oil and Gas Operations

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, 2016	
Proved oil and gas properties	$ 480,499
Unproved oil and gas properties	33,354
	513,853
Accumulated depreciation, depletion, amortization and impairment	(169,335)
Net capitalized costs	$ 344,518
December 31, 2015	
Proved oil and gas properties	$ 5,972,666
Unproved oil and gas properties	18,839
	5,991,505
Accumulated depreciation, depletion, amortization and impairment	(5,540,952)
Net capitalized costs	$ 450,553

There were $33.4 million of unproved property costs at December 31, 2016 excluded from the amortizable base. The December 31, 2016 balance represents the fair value of the Company's unproved oil and gas properties upon emergence from bankruptcy and implementation of Fresh Start Accounting on April 22, 2016 less cost transferred to proved through December 31, 2016. 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, 2016 and 2015.

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

	Successor	Predecessor		
	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015	Year Ended December 31, 2014
Lease acquisitions and prospect costs	$ 6,466	$ 2,695	$ 28,571	$ 44,162
Exploration	—	—	—	—
Development (1) (3)	40,908	24,082	74,948	327,878
Total acquisition, exploration, and development (2)	$ 47,374	$ 26,777	$ 103,519	$ 372,040

(1) Facility construction costs and capital costs have been included in development costs, and totaled $6.0 million, $2.2 million, $5.5 million and $47.0 million for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), respectively.

(2) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $5.4 million, $2.9 million, $12.7 million and $26.3 million for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor), and the years ended December 31, 2015 and 2014 (predecessor), respectively. In addition, the total includes $0.5 million, $4.9 million and $5.0 million for the period of April 23, 2016 through December 31, 2016 (successor) and the years ended December 31, 2015 and 2014 (predecessor), respectively, of capitalized interest on unproved properties. There was no capitalized interest on unproved properties for the period of January 1, 2016 through April 22, 2016 (predecessor) due to our bankruptcy proceedings.

(3) Includes asset retirement obligations incurred, including revisions, of approximately $8.0 million, $0.4 million, ($10.3 million) and ($3.7 million) for the period of April 23, 2016 through December 31, 2016 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the years ended December 31, 2015 and 2014 (predecessor), respectively.

Supplementary Reserves Information. The following information presents estimates of our proved oil and natural gas reserves. Reserves were prepared in accordance with SEC rules by H. J. Gruy and Associates, Inc. ("Gruy") as of December 31, 2016 and Gruy audited 99% and 97% of our proved reserves as of December 31, 2015 and 2014, respectively. The decrease in reserves in 2015 were due to lower commodity prices and uncertainties, due in part to our bankruptcy filing, surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves, as disclosed in Note 1A of the consolidated financial statements.

Estimates of Proved Reserves	**Total** (Boe)	**Natural Gas** (Mcf)	**Oil** (Bbls)	**NGL** (Bbls)
Proved reserves as of December 31, 2014 (5)	193,826,433	686,747,086	49,706,258	29,662,327
Revisions of previous estimates (1) (5)	(112,895,177)	(334,147,002)	(37,191,224)	(20,012,785)
Extensions, discoveries, and other additions (3)	487,939	2,927,633	—	—
Production (5)	(11,146,185)	(43,839,319)	(2,406,201)	(1,433,431)
Proved reserves as of December 31, 2015 (5)	70,273,010	311,688,398	10,108,833	8,216,111
Revisions of previous estimates (1) (5)	54,446,615	270,749,891	1,821,443	7,500,190
Sales of minerals in place (4)	(7,058,263)	(7,915,022)	(4,844,064)	(895,030)
Extensions, discoveries, and other additions (3)	15,467,483	92,804,900	—	—
Production (5)	(9,171,978)	(40,539,807)	(1,308,521)	(1,106,822)
Proved reserves as of December 31, 2016 (5)	123,956,867	626,788,360	5,777,691	13,714,449
Proved developed reserves (2):				
December 31, 2014	66,285,034	232,806,911	14,989,353	12,494,529
December 31, 2015	56,334,309	238,355,707	10,108,833	6,499,524
December 31, 2016	63,038,972	312,125,091	4,512,842	6,505,282
Proved undeveloped reserves (6)				
December 31, 2014	127,541,399	453,940,175	34,716,905	17,167,798
December 31, 2015	13,938,701	73,332,691	—	1,716,587
December 31, 2016	60,917,935	314,663,510	1,264,849	7,209,167

(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 net increase in reserves in 2016 was primarily due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing. The decrease in reserves in 2015 were due to lower commodity prices and uncertainties, due in part to our bankruptcy filing, surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves, as disclosed in Note 1A of the consolidated financial statements. Proved reserves, as of December 31, 2016, 2015 and 2014, 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 which are held constant, for that year's reserves calculation. The 12-month 2016 average adjusted prices after differentials used in our calculations were $2.43 per Mcf of natural gas, $41.07 per barrel of oil, and $16.13 per barrel of NGL compared to $2.61 per Mcf of natural gas, $49.58 per barrel of oil, and $14.64 per barrel of NGL for the 12-month average 2015 prices and $4.32 per Mcf of natural gas, $93.64 per barrel of oil, and $33.00 per barrel of NGL for the 12-month average 2014 prices.
(2) At December 31, 2016, 2015 and 2014, 51%, 80% and 34% of our reserves were proved developed, respectively.
(3) We have added proved reserves through our drilling activities, including, 0.5 MMBoe added in 2015. The 2016 additions were primarily due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing, partially offset by the sale of our Louisiana and other properties. The 2015 and 2016 extensions were all in the Fasken Eagle Ford area.
(4) Includes the disposition of our Lake Washington, Masters Creek, Burr Ferry, South Bearhead Creek and Sun TSH fields. See Note 10 of the consolidated financial statements in our Form 10-K for more information.
(5) The Company's reserves volumes exclude gas consumed in operations. Effective in our December 31, 2014 reserves volumes, we excluded natural gas volumes expected to be consumed in future operations from our reserves volumes. The effect of this change is included in the table above under Revision of previous estimates during 2014, and all amounts shown during 2015 and 2016 exclude these natural gas volumes. This change does not impact our cash flow or PV10 projections as the prices are adjusted accordingly.
(6) The increase in proved undeveloped reserves during 2016 was due to additions of undeveloped reserves which were previously not included because of the uncertainties surrounding the availability of the financing that would be necessary to develop them, due in part to our bankruptcy filing. The decrease in proved undeveloped reserves during 2015 were due to lower commodity prices and uncertainties, due in part to our bankruptcy filing, surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves, as disclosed in Note 1A of the consolidated financial statements in our Form 10-K.

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):

	As of December 31,		
	2016	2015	2014
Future gross revenues	$ 1,980,642	$ 1,434,931	$ 8,597,119
Future production costs	(750,823)	(688,427)	(2,447,318)
Future development costs (1)	(365,064)	(280,252)	(2,256,328)
Future net cash flows before income taxes	864,755	466,252	3,893,473
Future income taxes	(88,775)	(297)	(773,688)
Future net cash flows after income taxes	775,980	465,955	3,119,785
Discount at 10% per annum	(368,987)	(92,190)	(1,468,111)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 406,993	$ 373,765	$ 1,651,674

(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 as of December 31, 2016, 2015 and 2014, were 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, 2016, 2015 and 2014:

	2016	2015	2014
Beginning balance	$ 373,765	$ 1,651,674	$ 2,001,781
Revisions to reserves proved in prior years:			
Net changes in prices, net of production costs	(46,553)	(2,018,065)	(208,597)
Net changes in future development costs	(152,600)	817,324	(19,651)
Net changes due to revisions in quantity estimates	264,124	(599,342)	(5,762)
Accretion of discount	33,327	194,326	242,464
Other	28,888	119,483	(236,996)
Total revisions	127,186	(1,486,274)	(228,542)
New field discoveries and extensions, net of future production and development costs	75,034	3,025	38,301
Sales of minerals in place	(76,327)	—	(128,939)
Sales of oil and gas produced, net of production costs	(93,945)	(137,251)	(396,399)
Previously estimated development costs incurred	36,218	51,149	234,184
Net change in income taxes	(34,938)	291,442	131,288
Net change in standardized measure of discounted future net cash flows	33,228	(1,277,909)	(350,107)
Ending balance	$ 406,993	$ 373,765	$ 1,651,674

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the period of January 1, 2016 through April 22, 2016 (predecessor), period of April 23, 2016 through December 31, 2016 (successor) and the year ended December 31, 2015 (predecessor) (in thousands, except per share data):

	Revenues	Net Income (Loss) Before Taxes	Net Income (Loss)	Basic EPS	Diluted EPS
January 1 - April 22, 2016 (Predecessor)					
First [(1)]	$ 34,272	$ (108,303)	$ (108,303)	$ (2.42)	$ (2.42)
April 1 - April 22, 2016	8,510	959,914	959,914	21.45	21.03
Total	42,782	851,611	851,611	19.06	18.64
April 23 - December 31, 2016 (Successor)					
April 23 - June 30, 2016 [(1)]	20,653	(149,601)	(149,601)	(14.96)	(14.96)
Third	50,591	394	394	0.04	0.04
Fourth	30,293	(7,081)	(7,081)	(0.71)	(0.71)
Total	$ 101,537	$ (156,288)	$ (156,288)	$ (15.61)	$ (15.61)
2015 (Predecessor)					
First	$ 68,337	$ (556,568)	$ (477,077)	$ (10.79)	$ (10.79)
Second	66,169	(293,509)	(292,867)	(6.58)	(6.58)
Third	60,116	(354,588)	(354,588)	(7.96)	(7.96)
Fourth	50,099	(529,849)	(529,439)	(11.88)	(11.88)
Total [(1)]	$ 244,721	$ (1,734,514)	$ (1,653,971)	$ (37.20)	$ (37.20)

(1) Primarily due to pricing differences between the 12-month average oil and gas prices used in the Ceiling Test and the forward strip prices used to estimate the initial fair value of oil and gas properties on the Company's April 22, 2016 (successor) balance sheet, we incurred a non-cash impairment write-down for the period of April 23, 2016 through December 31, 2016 (successor) of $133.5 million. The full amount of this write-down was incurred as of June 30, 2016. Write-downs in prior periods were primarily the result of declining historical prices along with timing changes and reduction of projects and changes in our reserves product mix. For the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended 2015 (predecessor) we reported non-cash impairment write-downs on a before-tax basis of $77.7 million and $1.6 billion, respectively.

The sum of the individual quarterly net income (loss) 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 amounts because to do so would have been antidilutive.

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

None.

Item 9A. Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this annual report on Form 10-K and have determined that such disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with our May 16, 2017 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 16, 2017 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 16, 2017 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 16, 2017 annual shareholders' meeting is incorporated herein by reference.

Item 14. Principal Accounting 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 16, 2017 annual shareholders' meeting is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 27, 2017 and BDO USA, LLP dated February 27, 2017, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

None.

Item 16. Form 10-K Summary

None.

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3. Exhibits

2.1	Second Amended Joint Plan of Reorganization of the Debtors and Debtors in Possession dated March 28, 2016 (incorporated by reference as Exhibit 2.1 to Swift Energy Company's Form 8-K filed April 6, 2016, File No. 001-08754).
3.1	Certificate of Incorporation of Swift Energy Company (incorporated by reference as Exhibit 3.1 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
3.2	Bylaws of Swift Energy Company (incorporated by reference as Exhibit 3.2 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
4.1	Form of stock certificate for common stock, $0.01 par value per share (incorporated by reference as Exhibit 4.6 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
4.2	Registration Rights Agreement, dated as of April 22, 2016, by and among Swift Energy Company and the stockholders party thereto (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).
4.3	Director Nomination Agreement, dated as of April 22, 2016, by and among Swift Energy Company and the stockholders party thereto (incorporated by reference as Exhibit 4.7 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.1	Senior Secured Revolving Credit Agreement, dated April 22, 2016, among Swift Energy Company, JPMorgan Chase Bank, National Association and the Lenders party thereto (incorporated by reference as Exhibit 10.3 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).
10.2	Warrant Agreement, dated as of April 22, 2016, between Swift Energy Company and American Stock Transfer & Trust Company, LLC (incorporated by reference as Exhibit 10.4 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).
10.3+	Swift Energy Company 2016 Equity Incentive Plan (incorporated by reference as Exhibit 4.1 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.4+	Form of Stock Option Agreement - Emergence Grant (Type I) (incorporated by reference as Exhibit 4.2 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.5+	Form of Stock Option Agreement - Emergence Grant (Type II) (incorporated by reference as Exhibit 4.3 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.6+	Form of Restricted Stock Unit Agreement - Emergence Grant (Type I) (incorporated by reference as Exhibit 4.4 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.7+	Form of Restricted Stock Unit Agreement - Emergence Grant (Type II) (incorporated by reference as Exhibit 4.5 to Swift Energy Company's Form S-8 filed April 27, 2016, File No. 333-210936).
10.8+	Form of Restricted Stock Unit Agreement - Non Employee Directors (incorporated by reference as Exhibit 10.1to Swift Energy Company's Form 8-K filed June 14, 2016, File No. 001-08754)
10.9+	Form of Stock Option Agreement- Non Employee Directors (incorporated by reference as Exhibit 10.2 to Swift Energy Company's Form 8-K filed June 14, 2016, File No. 001-08754).
10.10+	Swift Energy Company Inducement Plan (incorporated by reference as Exhibit 4.4 to Swift Energy Company's Form S-8 filed December 21, 2016, File No. 333-21535).
10.11+	Form of Restricted Stock Unit Agreement - Inducement Plan (incorporated by reference as Exhibit 4.5 to Swift Energy Company's Form S-8 filed December 21, 2016, File No. 333-21535).
10.12+	Form of Stock Option Agreement - Inducement Plan (incorporated by reference as Exhibit 4.6 to Swift Energy Company's Form S-8 filed December 21, 2016, File No. 333-215235).
10.13+	Third Amended and Restated Executive Employment Agreement of Terry E. Swift dated April 22, 2016 (incorporated by reference as Exhibit 10.5 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).
10.14+	First Amended and Restated Executive Employment Agreement of Robert J. Banks dated April 22, 2016 (incorporated by reference as Exhibit 10.6 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).
10.15+	Third Amended and Restated Executive Employment Agreement of Alton D. Heckaman, Jr. dated April 22, 2016 (incorporated by reference as Exhibit 10.7 to Swift Energy Company's Form 8-K filed April 28, 2016, File No. 001-08754).

10.16+	Amendment to Third Amended and Restated Executive Employment Agreement of Alton D. Heckaman, Jr. effective November 15, 2016 (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed November 16, 2016, File No. 001-08754).
10.17+	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. 001-08754).
10.18+	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 March 1, 2007, File No. 001-08754).
16	Letter from Ernst & Young LLP dated June 14, 2016, to the Securities and Exchange Commission regarding change in certifying accountant (incorporated by reference as Exhibit 16.1 to Swift Energy Company's Form 8-K filed June 14, 2016, File No. 001-08754).
21 *	List of Subsidiaries of Swift Energy Company.
23.1 *	Consent of H.J. Gruy and Associates, Inc.
23.2 *	Consent of Ernst & Young LLP as to incorporation by reference regarding Form S-8 Registration Statements.
23.3*	Consent of BDO USA, LLP as to incorporation by reference regarding Form 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 January 24, 2017.
99.2	Findings of Fact, Conclusions of Law and Order Confirming Pursuant to Section 1129(a) and (b) of the Bankruptcy Code the Joint Plan of Reorganization of the Debtors and Debtors in Possession, as entered by the Bankruptcy Court on March 31, 2016 (incorporated by reference as Exhibit 99.1 to Swift Energy Company's Form 8-K filed April 6, 2016, File No. 001-08754).
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.

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.

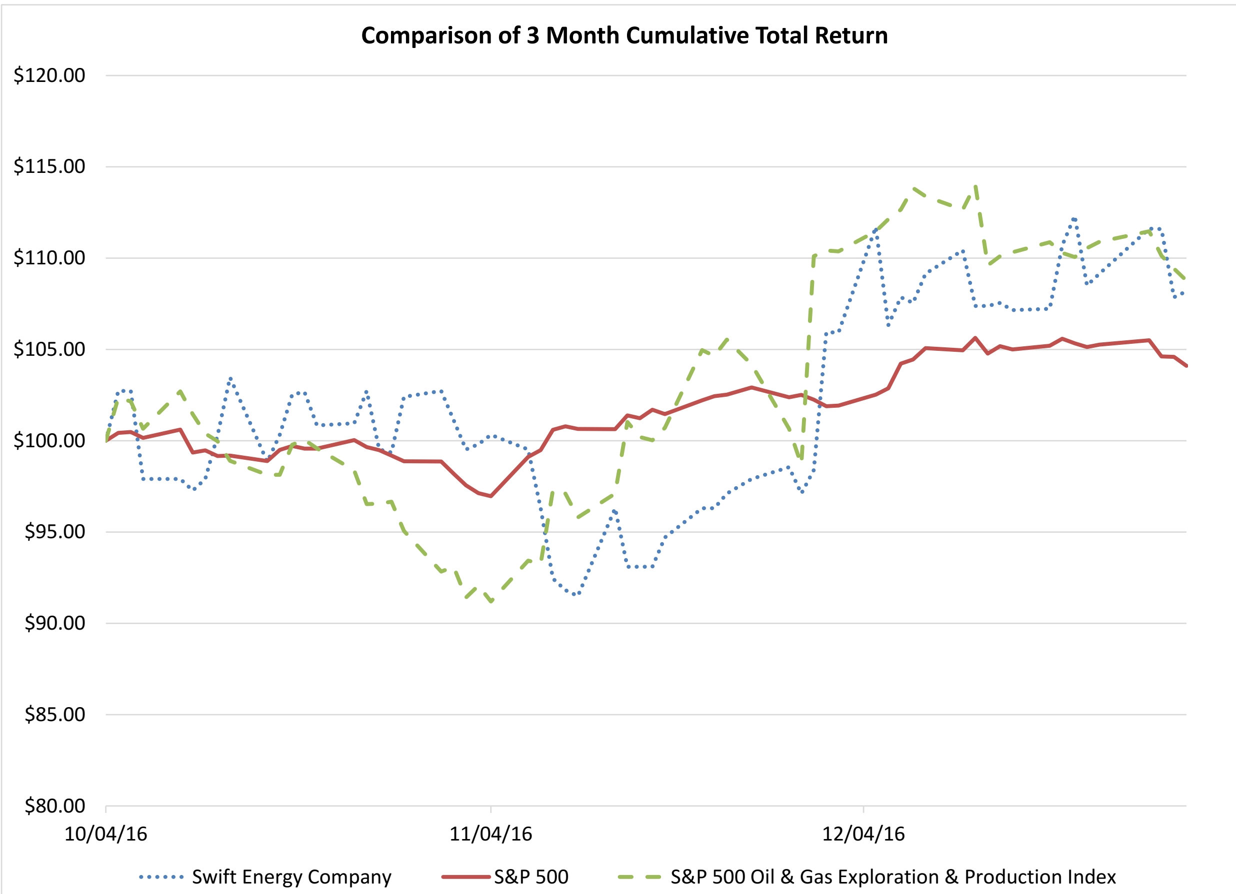
SWIFT ENERGY COMPANY

By: /s/ Robert J. Banks
Robert J. Banks
Interim Chief Executive Officer

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/ Robert J. Banks Robert J. Banks	Interim Chief Executive Officer	February 27, 2017
/s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr.	Executive Vice President Chief Financial Officer Principal Accounting Officer	February 27, 2017
/s/Marcus C. Rowland Marcus C. Rowland	Chairman of the Board Director	February 27, 2017
/s/ Michael Duginski Michael Duginski	Director	February 27, 2017
/s/ Gabriel L. Ellisor Gabriel L. Ellisor	Director	February 27, 2017
David Geenberg	Director	February 27, 2017
/s/ Christoph O. Majeske Christoph O. Majeske	Director	February 27, 2017
/s/ Charles W. Wampler Charles W. Wampler	Director	February 27, 2017

The following graph compares the cumulative total return to our stockholders on our common stock from October 4, 2016 to December 31, 2016, relative to the cumulative returns of the S&P 500 and the S&P Oil & Gas Exploration & Production Index for the same period. The period illustrated is the date that our common stock began trading on the OTCQX market following our emergence from bankruptcy. From January 1, 2016 to October 3, 2016, the stock of the Company, (including both the old common stock that was cancelled when we emerged from bankruptcy on April 22, 2016, and the new common stock that was issued upon our emergence), was not trading on a recognizable exchange or platform and, as such, this period is not reported in the below graph.



INVESTOR INFORMATION

BOARD OF DIRECTORS

Marcus C. Rowland, Chairman
Founder & Senior Managing Director,
IOG Capital

Michael Duginski
President & Chief Executive Officer,
Sentinel Peak Resources

Gabriel L. Ellisor
Retired Chief Financial Officer,
Three Rivers Operating Company

David Geenberg
Co-Head of North American
Investment Team,
Strategic Value Partners

Christoph O. Majeske
Director,
Strategic Value Partners

Charles W. Wampler
Retired Chief Operating Officer,
Aspect Holdings

Sean C. Woolverton
Chief Executive Officer,
Swift Energy Company

OFFICERS

Sean C. Woolverton
Chief Executive Officer

Robert J. Banks
Executive Vice President & Chief
Operating Officer

G. Gleeson Van Riet
Executive Vice President & Chief
Financial Officer

Christopher M. Abundis
Senior Vice President, General
Counsel & Secretary

In addition to the officers above, the following are officers of the Company's principal domestic operating subsidiary, Swift Energy Operating, LLC:

Randy A. Bailey
Vice President – Operations

Michael S. Coffield
Vice President – Transactions, Land &
Business Development

Stephen P. Schmitt
Vice President – Energy Marketing

Steven B. Yakle
Vice President—Corporate
Administration

CORPORATE HEADQUARTERS

Swift Energy Company
575 North Dairy Ashford
Suite 1200
Houston, Texas 77079
Telephones: (281) 874-8700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANY

Swift Energy Operating, LLC
Houston, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer
& Trust Company
6201 15th Avenue
Brooklyn, New York 11219

EXCHANGE LISTING

OTCQX: SWTF

INDEPENDENT AUDITOR

BDO USA, LLP
2929 Allen Pkwy, 20th Floor
Houston, Texas 77019

COUNSEL

Vincent & Elkins LLP
1001 Fannin, Suite 2500
Houston, Texas 77002