Section 1: 10-K (2017 10-K)

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, 2017

Commission File Number 1-8754

SILVERBOW RESOURCES, INC.
(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	New York Stock Exchange

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

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

Yes ☐ 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, a non-accelerated filer, a smaller reporting company or an emerging growth company. See definition of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☑	Non-accelerated filer	☐	Smaller reporting company	☐
Emerging Growth Company	☐						

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

☐

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 New York Stock Exchange as of June 30, 2017, the last business day of June 2017, was approximately $86,619,851.

The number of shares of common stock outstanding as of February 26, 2018 was 11,616,482.

Explanatory Note

SilverBow Resources, Inc. was formerly known as Swift Energy Company. On May 5, 2017, through amendments to its Certificate of Incorporation and Bylaws, Swift Energy Company changed its name to SilverBow Resources, Inc. Additionally, SilverBow Resources, Inc. began trading on the New York Stock Exchange (“NYSE”) under the ticker symbol “SBOW” on May 5, 2017.

Form 10-K

SilverBow Resources, Inc. 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 “SilverBow Resources,” “the Company,” “we,” “our,” “ours” and “us” refer to SilverBow Resources, Inc. See pages 29 and 30 for explanations of abbreviations and terms used herein.

Overview

SilverBow Resources is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas where we have assembled over 100,000 net acres across five operating areas. Our acreage positions in each of our operating areas are highly contiguous and designed for optimal and efficient horizontal well development. We have built a balanced portfolio of properties with a significant base of current production and reserves coupled with low-risk development drilling opportunities and meaningful upside from newer areas. We produced an average of 177 MMcfe per day during the fourth quarter of 2017 and had proved reserves of 1,024 MMcfe (82% natural gas) with a PV-10 of $805 million as of December 31, 2017. 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 most directly comparable GAAP measure.

Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoir characteristics, geology, landowners, and competitive landscape in the region. We leverage this in-depth knowledge to continue to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested.

We have transformed the Company from a conventional, Louisiana shallow water producer to a focused Eagle Ford player. Over the last few years we have successfully renegotiated midstream contracts, moved our headquarters to west Houston, and reduced headcount over 50% since 2015. These initiatives have resulted in a reduction of per unit G&A from $0.64/Mcfe at year end 2015 to $0.53/Mcfe at year end 2017, a 17% reduction. We expect to continue improving our G&A metrics as we execute on our strategic growth program. We continue to refine our portfolio, including the sale of certain AWP Olmos wells on March 1, 2018. This strategic divestiture allows us to better leverage existing personnel while lowering field-level costs on a per unit basis. We believe there are other opportunities to continue streamlining our business to extract value for our shareholders.

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 Notes 12 and 13 in our Consolidated Financial Statements in this Form 10-K.

Business Strategies

- *Leverage technical expertise to efficiently develop our extensive drilling inventory of high rate of return Eagle Ford shale drilling locations*. Our technical team has an average of over 25 years of experience and has drilled over 200 horizontal wells in the Eagle Ford which we believe gives us a technical advantage when developing and organically expanding our asset base. We leverage this advantage in our existing asset base to create highly efficient drilling and completion operations. Focusing solely 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 asset value through utilizing cost-effective technology to locate the highest quality intervals to drill and complete oil and gas wells. We have optimized our drilling techniques which have shortened our drill times and allowed us steer our laterals to target a narrow high quality interval of the lower Eagle Ford. We have also enhanced fracture stimulation design using more pounds of proppant and tighter fracture stage spacing while continuing to lower well costs. These factors have further enhanced the return profile of our drilling and completion operations. In 2018, we plan to invest between $245 and $265 million on our Eagle Ford operations to drill 32 net (38 gross) horizontal wells. The 2018 drilling program represents approximately 5% of the total inventory of 667 horizontal wells we have identified across our position.

- *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 essentially all of our properties enables us to apply drilling and completion techniques and economies of scale that improve returns. Operating control allows us to manage pace of development, timing, and associated annual capital expenditures. Furthermore, we are able to achieve lower operating costs through concentrated infrastructure and field operations. In addition, our concentrated acreage positions allow the Company to drill multiple wells from a single pad while optimizing lateral lengths. Pad drilling reduces facilities costs and consolidates surface level operations. Our operational control is critical to us being able to transfer successful drilling and completion techniques and cost cutting initiatives from one field to another. Finally, we will continue to leverage our proximity to end user markets of natural gas which gives us the ability to lower transportation costs relative to other basins and enhance returns to shareholders.

- *Continue to pursue strategic opportunities to further expand our core position in the Eagle Ford.* We continue to take advantage of opportunities to expand our core positions through leasing and bolt-on acquisitions as evidenced by the approximate 36,500 acres we acquired during 2017 which represented a 59% increase over our acreage position at year end 2016. We plan to strategically target certain areas of the Eagle Ford where our technical experience and successful drilling results can be replicated and expanded. Our Eagle Ford portfolio provides us with a multi-decade growth platform that continues to improve in response to our successful drilling program. We believe we have the extensive basin-wide experience that gives us a competitive advantage in locating both strategic acquisitions and ground-floor leasing opportunities to expand our core acreage position in the future.

- *Maintain our financial flexibility and strong liquidity profile.* We are committed to preserving our financial flexibility and are focused on continued growth in a disciplined manner. We have historically funded our capital program by using a combination of internally generated cash flows and funds available on our Credit Facility. As of December 31, 2017, the Company had approximately $260 million of liquidity, which we believe provides us with a sufficient amount of liquidity to execute on our 2018 development plan and opportunistically acquire or lease additional acreage even with modest changes in the commodity environment. Our Credit Facility and Senior Secured Second Lien Notes, maturing in April 2022 and December 2024, respectively, are our only stated debt maturities.

- *Manage risk exposure.* We utilize a disciplined hedging program to limit our exposure to volatility in commodity prices and achieve a more predictable level of cash flows to support current and future capital expenditure plans. Our multi-year hedging program also hedges to limit our basis differential to Henry Hub pricing. We take a systematic approach to hedging and consistently add hedges to our portfolio at prices that ensure adequate rates of returns on our drilling program. As of December 31, 2017 we had approximately 53% of total production volumes hedged for full year 2018 using the mid-point of production guidance of 175 to 195 Mmcfe/d.

Our Competitive Strengths

- *Extensive inventory of high rate of return drilling locations with high degree of operational control.* We have developed a significant inventory of future drilling locations, primarily in our well-established gas position in the Eagle Ford. As of December 31, 2017, we had approximately 100,000 net acres in the Eagle Ford and roughly 667 horizontal drilling locations. Approximately 55% of our estimated proved reserves at December 31, 2017 were undeveloped. We operate essentially all of our proved reserves and have an average working interest of approximately 92% across our identified locations. These factors provide us with a high level of control over our operations, allowing us to manage our development drilling schedule, utilize pad drilling where applicable, and implement leading edge modern completion techniques. We plan to continue to deliver production, reserve and cash flow growth by developing our extensive inventory of low-risk drilling locations in a disciplined manner.

- *Balanced portfolio mix of proved producing assets and low-risk development with significant upside from newer areas.* Our average daily production for the full year 2017 was 153.8 MMfce/d and our proved developed reserves were 458 Bcfe representing approximately $470 million of PV-10. Our portfolio of properties and our 2018 capital plan couples this strong base of production and reserves with low risk in-fill drilling in our Fasken Area where we plan to drill 13 net wells in 2018. We have identified a total of 156 drilling locations in this area prospective for the lower and upper Eagle Ford and Austin Chalk. In addition, our plan allows us to capture the significant upside associated with our recent success in our newer Oro Grande Area. In 2017, we successfully drilled two wells in Oro Grande and in 2018 we plan to drill an additional 5 net wells in this area. This area is comprised of a blocky and contiguous 24,884 net acres where we have identified 104 additional drilling locations. We believe that our balanced portfolio and development approach allow us to deliver low-risk production and reserve growth and expose shareholders to significant upside and organic inventory expansion.

- *Proximity to Demand Centers.* Our assets are positioned in one of the most economically advantaged natural gas regions of North America. Our proximity to the Gulf Coast affords us much lower natural gas basis differentials and meaningfully higher price realizations when compared to other natural gas plays, such as those in the Marcellus and the Utica. For instance, in 2017 our average natural gas basis differentials to NYMEX were $0.07/Mcfe discount vs. $0.87 Mcfe discount at Dominion in the northeastern natural gas markets. Additionally, our assets are in close proximity to the largest and highest growth natural gas and NGL demand centers, including increasing LNG exports, natural gas exports to Mexico and industrial, petrochemical, and power demand in the Gulf Coast markets.

- *Experienced and proven technical team.* We employ 17 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 25 years of experience in their technical fields. Our senior technical team has come from a number of large and successful organizations. Our technical team is focused on utilizing modern completion techniques to increase our EUR per 1,000 feet of lateral length and maximizing our per-well returns. Our enhanced completion designs include tighter fracture stage spacing as well as higher proppant loadings and intensity. Additionally, we rely on advanced technologies, such as micro-seismic analysis, to better define geologic risk and enhance the results of our drilling efforts. Due to these efforts, we have drilled 27 out of the top 50 natural gas wells in the Eagle Ford based on first year cumulative production based on data as of January 1, 2018. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

- *Proven low cost operator with blocky and contiguous acreage.* Our core acreage positions are blocky and contiguous in nature which allows us to continue to lower per unit costs through drilling longer laterals, utilizing pad drilling, consolidating in-field infrastructure, and efficiently sourcing materials through our rigorous procurement strategies. We believe the nature of our positions and our operational improvements and efficiencies will allow us to continue to successfully mitigate service cost inflation as activity increases. Additionally, we continually seek to optimize our production operations with the objective of reducing our operating costs through efficient well management. Finally, our significant operational control, as well as our manageable leasehold drilling obligations, provide us the flexibility to control our costs as we transition to a development mode across our portfolio.

- *Strong balance sheet and liquidity profile.* As of December 31, 2017, the Company had approximately $260 million of liquidity, which we believe provides us with a sufficient amount of liquidity to execute on our 2018 development plan and opportunistically acquire or lease additional acreage even with modest changes in the commodity environment. Our Credit Facility and Senior Secured Second Lien Notes, maturing in April 2022 and December 2024, respectively, are our only debt maturities. As of December 31, 2017, we had $73 million drawn on our $330 million Credit Facility.

Property Overview

Our operations are focused in three fields located in the Eagle Ford Shale trend of South Texas. The following table sets forth information regarding our Eagle Ford fields in 2017.

Fields	Acreage	2017 Production (MMcfe/d)	% Gas	2017 Wells Drilled	2017 Wells Completed
Artesia	12,811	20,256	44%	7	7
AWP	42,566	35,628	53%	2	2
Fasken	7,718	92,518	100%	6	10
Other (1)	37,026	5,392	96%	3	3
Total	**100,121**	**153,794**	**82%**	**18**	**22**

(1) Other includes Oro Grande, Uno Mas and non-core properties.

The following table sets forth information regarding our 2017 year-end proved reserves of 1,024.4 MMcfe and production of 56.1 Bcfe by area:

Fields	Proved Developed Reserves (MMcfe)	Proved Undeveloped Reserves (MMcfe)	Total Proved Reserves (MMcfe)	% of Total Proved Reserves	Oil and NGLs as % of Proved Reserves	Total Production (Mcfe)
Artesia	64.5	62.5	127.0	12.4%	53.7%	7,393.4
AWP Eagle Ford	75.1	229.3	304.4	29.7%	33.2%	8,910.0
AWP Olmos	29.9	—	29.9	2.9%	40.4%	4,094.3
Fasken	267.9	243.0	510.9	49.9%	—%	33,769.2
Other (1)	20.8	31.3	52.2	5.1%	0.4%	1,968.0
Total	**458.2**	**566.2**	**1,024.4**	**100.0%**	**17.7%**	**56,134.9**

(1) Other includes Oro Grande, Uno Mas and non-core properties.

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, 2017, 2016 and 2015. 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., independent petroleum engineers, prepared our proved reserves report as of December 31, 2017 and 2016 and audited 99% of our proved reserves as of December 31, 2015. Our 2015 reserves report was prepared internally under the supervision of our Chief Reservoir Engineer. The 2015 reserves audit by H.J. Gruy and Associates conformed to the meaning of the term “reserves audit” as presented in Regulation S-K, Item 1202. Reserve data used for interim reporting periods were 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 2017 and 2016 reserve reports. All information from our secure engineering database as well as geographic maps, well logs, production tests and other pertinent data were provided to H.J. Gruy and Associates.

The Chief Reservoir Engineer supervises this process with multiple levels of review and reconciliation of reserve estimates to ensure they conform to SEC guidelines. Reserves data are also reported to and reviewed by senior management quarterly. The Board of Directors review the reserve data periodically and the independent Board members meet with H.J. Gruy and Associates, Inc. in executive sessions at least annually.

The technical person at H.J. Gruy and Associates, Inc. primarily responsible for overseeing preparation of the 2017 and 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 2017 and 2016 reserve 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, 2017, 2016 and 2015 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 2017 average adjusted prices after differentials were $2.95 per Mcf of natural gas, $50.38 per barrel of oil, and $20.32 per barrel of NGL, compared to $2.43 per Mcf of natural gas, $41.07 per barrel of oil, and $16.13 per barrel of NGL for 2016 and $2.61 per Mcf of natural gas, $49.58 per barrel of oil, and $14.64 per barrel of NGL for 2015.

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 (the most directly comparable financial measure calculated in accordance with U.S. GAAP) and PV-10 Value of the Company's proved reserves.

	As of December 31,		
(in millions)	**2017**	**2016**	**2015**
PV-10 Value	**$ 805**	**$ 442**	**$ 374**
Less: Future income taxes (discounted at 10%)	73	35	—
Standardized Measure of Discounted Future Net Cash Flows	**$ 732**	**$ 407**	**$ 374**

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, 2017, 2016 and 2015. 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, 2017, we had estimated proved reserves of 1,024.4 MMcfe with a Standardized Measure of $732 million and PV-10 Value of $805 million. This is an increase of approximately 281 MMcfe from our year-end 2016 proved reserves quantities primarily due to drilling and an expanded development plan. Our total proved reserves at December 31, 2017 were approximately 4% crude oil, 82% natural gas, and 14% NGLs, while 45% of our total proved reserves were developed. All of our proved reserves are located in Texas. The following amounts shown in MMcfe below are based on an oil conversion factor of 1 Boe to 6 Mcf:

Estimated Proved Natural Gas, Oil and NGL Reserves	**As of December 31,**		
	2017	**2016**	**2015**
Natural gas reserves (MMcf):			
Proved developed	377,506	312,125	238,356
Proved undeveloped [3]	465,230	314,664	73,332
Total	842,736	626,789	311,688
Oil reserves (MBbl):			
Proved developed	5,027	4,513	10,109
Proved undeveloped [3]	2,133	1,265	—
Total	7,160	5,778	10,109
NGL reserves (MBbl):			
Proved developed	8,431	6,505	6,500
Proved undeveloped [3]	14,690	7,209	1,716
Total	23,121	13,714	8,216
Total Estimated Reserves (MMcfe) [1][3]	**1,024,422**	**743,742**	**421,638**
Standardized Measure of Discounted Future Net Cash Flows (in millions) [2]	**$ 732**	**$ 407**	**$ 374**
PV-10 by reserve category			
Proved developed	$ 470	$ 252	$ 321
Proved undeveloped	335	190	53
Total PV-10 Value [2]	**$ 805**	**$ 442**	**$ 374**

(1) The reserve volumes exclude natural gas consumed in operations.
(2) The Standardized Measure and PV-10 Values as of December 31, 2017, 2016 and 2015 are net of $7.1 million, $33.1 million and $57.8 million of plugging and abandonment costs, respectively.
(3) The increase in 2016 reserves volumes was primarily due to rebooking of proved undeveloped reserves that we removed in 2015 due to uncertainty about available financing. The increase in 2017 was primarily attributable to extensions added based on drilling results and leasing of adjacent acreage.

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, 2017:

Year Added	Volume (MMcfe)	% of PUD Volumes
2017	313.5	55%
2016 (1)	252.7	45%
2015	0.0	—%
2014	0.0	—%
2013	0.0	—%
Total	**566.2**	**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 as of December 31, 2016 were 2016 additions.

During 2017, our proved undeveloped reserves increased by approximately 200.7 MMcfe primarily due to additions of undeveloped reserves in our AWP and Oro Grande fields, partially offset by 2016 undeveloped reserves which were converted to proved developed reserves during 2017. We also incurred approximately $89.5 million in capital expenditures during the year which resulted in the conversion of 115.5 MMcfe of our December 31, 2016 proved undeveloped reserves to proved developed reserves, primarily in the Fasken field.

The PV-10 Value from our proved undeveloped reserves was $335 million at December 31, 2017, which was approximately 42% of our total PV-10 Value of $805 million. The PV-10 Value of our proved undeveloped reserves, by year of booking was 54% in 2017 and 46% in 2016.

Sensitivity of Reserves to Pricing

As of December 31, 2017, a 5% increase in natural gas pricing would increase our total estimated proved reserves by approximately 2.5 MMcfe and would increase the PV-10 Value by approximately $57.6 million. Similarly, a 5% decrease in natural gas pricing would decrease our total estimated proved reserves by approximately 2.7 MMcfe and would decrease the PV-10 Value by approximately $57.2 million.

As of December 31, 2017, a 5% increase in oil and NGL pricing would increase our total estimated proved reserves of 1,024.4 MMcfe by approximately 1.8 MMcfe, and would increase the PV-10 Value of $805 million by approximately $19.5 million. Similarly, a 5% decrease in oil and NGL pricing would decrease our total estimated proved reserves by approximately 1.9 MMcfe and would decrease the PV-10 Value by approximately $19.4 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, 2017			
Gross	166	543	709
Net	161.7	500	661.7
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

(1) Excludes 8, 9 and 48 service wells in 2017, 2016 and 2015.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2017:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Texas (1)	57,357	53,650	71,973	62,110
Colorado(2)	—	—	21,922	20,997
Louisiana	5,084	4,775	4,920	4,478
Wyoming	—	—	3,013	1,442
Total	**62,441**	**58,425**	**101,828**	**89,027**

(1) The Company's total acreage in Eagle Ford includes 112,804 gross and 100,121 net acres.
(2) The Company's leasehold acreage in Colorado is scheduled to expire in 2018. The Company has no plans to extend these leases and plans to let them expire.

As of December 31, 2017, SilverBow Resources' net undeveloped acreage subject to expiration over the next three years, if not renewed, is approximately 25% in 2018, 2% in 2019 and 7% in 2020. In most cases, acreage scheduled to expire can be held through drilling operations or we can exercise extension options. As of February 28, 2018, 3,387 net undeveloped acres, primarily in Colorado, have expired during 2018. 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 and completion activities during the years ended December 31, 2017, 2016 and 2015:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2017	Exploratory	—	—	—	—	—	—
	Development	27	27	—	22.0	22.0	—
2016	Exploratory	—	—	—	—	—	—
	Development	8	8	—	5.1	5.1	—
2015	Exploratory	—	—	—	—	—	—
	Development	24	24	—	17.1	17.1	—

Recent Activities

As of December 31, 2017, we were in the process of drilling six wells in our Fasken field where we have a 64% working interest. These wells were completed in the first quarter of 2018.

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 in 2017 totaled $4.7 million and ranged from $125 to $1,301 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 year ended December 31, 2017 (successor), 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) parties which accounted for approximately 10% or more of our total oil and gas receipts were as follows:

	Successor		Predecessor	
Sellers greater than 10%	**Year Ended December 31, 2017**	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**	**Year Ended December 31, 2015**
Kinder Morgan	48%	38%	20%	27%
Plains Marketing (1)	—%	14%	14%	18%
Howard Energy (1)	—%	—%	11%	13%
Southcross Energy (1)	—%	—%	11%	—%
Shell (1)	—%	15%	19%	16%

(1) Less than 10% for the year ended December 31, 2017 (successor).

We have gas processing and gathering agreements with Southcross Energy for a majority of our natural gas production in the AWP area. 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.

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 year ended December 31, 2017 (successor), 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).

	Successor		Predecessor	
All Fields	**Year Ended December 31, 2017**	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**	**Year Ended December 31, 2015**
Net Sales Volume:				
Oil (MBbls)	685	786	522	2,406
Natural Gas Liquids (MBbls)	1,046	727	380	1,433
Natural gas (MMcf)	45,751	29,109	11,431	43,839
Total (MMcfe)	56,135	38,190	16,842	66,877
Average Sales Price:				
Oil (Per Bbl)	$ 50.98	$ 44.79	$ 31.43	$ 47.11
Natural Gas Liquids (Per Bbl)	$ 21.61	$ 16.39	$ 11.04	$ 14.54
Natural gas (Per Mcf)	$ 3.03	$ 2.55	$ 1.96	$ 2.56
Total (Per Mcfe)	$ 3.49	$ 3.18	$ 2.55	$ 3.68
Average Production Cost (Per Mcfe sold) (1)	$ 0.74	$ 1.00	$ 1.26	$ 1.38

(1) Average production cost includes lease operating costs, 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 83% of the Company's proved reserves based on total MMcfe as of December 31, 2017:

	Successor		Predecessor	
Fasken	**Year Ended December 31, 2017**	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**	**Year Ended December 31, 2015**
Net Sales Volume:				
Natural Gas Liquids (MBbls)	2	1	1	2
Natural gas (MMcf) (1)	33,757	20,762	7,274	28,598
Total (MMcfe)	33,769	20,770	7,277	28,611
Average Sales Price:				
Natural Gas Liquids (Per Bbl)	$ 18.13	$ 14.09	$ 3.87	$ 16.65
Natural gas (Per Mcf)	$ 3.02	$ 2.55	$ 1.96	$ 2.53
Total (Per Mcfe)	$ 3.02	$ 2.55	$ 1.96	$ 2.53
Average Production Cost (Per Mcfe sold) (2)	$ 0.59	$ 0.56	$ 0.58	$ 0.53

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

AWP	Successor: Year Ended December 31, 2017	Successor: Period from April 23, 2016 through December 31, 2016	Predecessor: Period from January 1, 2016 through April 22, 2016	Predecessor: Year Ended December 31, 2015
Net Sales Volume:				
Oil (MBbls)	427	388	206	1,047
Natural Gas Liquids (MBbls)	598	519	235	843
Natural gas (MMcf) [1]	6,857	6,438	3,061	10,372
Total (MMcfe)	13,004	11,878	5,704	21,711
Average Sales Price:				
Oil (Per Bbl)	$ 50.40	$ 44.54	$ 30.07	$ 45.37
Natural Gas Liquids (Per Bbl)	$ 20.87	$ 16.32	$ 11.31	$ 14.79
Natural gas (Per Mcf)	$ 3.09	$ 2.59	$ 1.90	$ 2.62
Total (Per Mcfe)	$ 4.25	$ 3.57	$ 2.57	$ 4.01
Average Production Cost (Per Mcfe sold) [2]	$ 1.25	$ 1.03	$ 1.31	$ 1.44

(1) Excludes natural gas consumed in operations.
(2) Average production cost includes lease operating costs, 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, 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 fourth quarter of 2020. For additional discussion related to our price-risk policy, refer to Note 5 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 reserve 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.

Environmental and Occupational Health and Safety Matters

Our business operations are subject to numerous federal, state and local environmental and occupational health and safety laws and regulations. Numerous governmental entities, including the U.S. Environmental Protection Agency (“EPA”), the U.S. Occupational Safety and Health Administration ("OSHA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (v) impose specific safety and health criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and completion activities.

The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the Clean Air Act (“CAA”), which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas emissions (“GHGs”);
- the Federal Water Pollution Control Act, also known as the federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the Resource Conservation and Recovery Act (“RCRA”), which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- the Oil Pollution Act of 1990, which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States;
- the Safe Drinking Water Act (“SDWA”), which ensures the quality of the nation’s public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;
- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;
- the Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas; and
- the National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment.

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Additionally, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in place of the government and sue operators for alleged violations of environmental law. See Risk Factors under Part I, Item 1A of this Form 10-K for further discussion on hydraulic fracturing; ozone standards, induced seismicity; climate change; and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve.

Many states, including Texas where we conduct operations, also have, or are developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. While the legal requirements imposed under state law may be similar in form to federal laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development or expansion of a project or substantially increase the cost of doing business. In addition, environmental and occupational health and safety laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental or worker health and safety concerns, are expected to continue to have an increasing impact on our operations.

We have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results.

Employees

As of December 31, 2017, the Company employed 87 people. None of our employees were represented by a union and relations with employees are considered to be good.

Facilities

At December 31, 2017, we occupied approximately 34,275 square feet of office space at 575 N. Dairy Ashford Road, Houston, Texas. For discussion regarding the term and obligations of this sub-lease refer to Note 6 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.sbow.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 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, during 2017 the WTI crude oil crude oil and Henry Hub natural gas spot prices ranged from approximately $42 to $60 per barrel and $2.44 to $3.71 per MMBtu, respectively. As of December 31, 2017, the spot market price for WTI was $60.46 while the spot market price for natural gas was $2.95. 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;
- stockholder activism or activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas;
- 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. 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 2018 capital expenditure budget, including expenditures for leasehold acquisitions, drilling and infrastructure and fulfillment of abandonment obligations is expected to be in the range of $245 million and $265 million. We had approximately $219.5 million of capital expenditures in 2017. 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.

Our Credit Facilities, as defined below, contain operating and financial restrictions that may restrict our business and financing activities.

Our Credit Facilities include (i) that certain amended and restated senior secured revolving credit facility among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto (defined herein as the “Credit Facility”) and (ii) that certain note purchase agreement among the Company, as issuer, U.S. Bank National Association, as agent and collateral agent and the holders party thereto (the “Second Lien”, together with the Credit Facility, our “Credit Facilities”). Our Credit Facilities contain a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- redeem our debt;
- make investments;

- incur or guarantee additional indebtedness;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into swap agreements beyond certain maximum thresholds;
- enter into sale and leaseback transactions; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our Credit Facilities may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or were to decline, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our Credit Facilities or any future indebtedness could result in an event of default under our Credit Facilities or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

If an event of default under either of our Credit Facilities occurs and remains uncured, the lenders or holders under the applicable Credit Facility:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings or notes outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings or notes; or
- may prevent us from making debt service payments under our other agreements.

In addition, our obligations under the Credit Facilities are collateralized by perfected first and second priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 85% of the PV-9 of the borrowing base properties (with respect to the Credit Facility) or the oil and gas properties constituting proved reserves as set forth in the most recent reserve report (with respect to the Second Lien), and if we are unable to repay our indebtedness under the Credit Facilities, the lenders could seek to foreclose on our assets.

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 22,126 net acres that could potentially expire during fiscal year 2018, representing approximately 25% of our net undeveloped acreage. Additionally, we have leases on 20,997 net acres in Colorado that are scheduled to expire in 2018. We have no plans to extend the leases for the Colorado acreage and plan to let them expire.

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.

We 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 natural gas properties in 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), and the year ended December 31, 2015 (predecessor), we reported non-cash write-downs on a before-tax basis of, $133.5 million, $77.7 million and $1.6 billion ($1.5 billion after-tax) respectively, on our oil and natural gas properties. There was no write-down for the year ended December 31, 2017 (successor). 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 1 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 2017 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 or other proppant and chemical additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. The Company uses 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 conducted studies or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the U.S. Environmental Protection Agency ("EPA") released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances. Additionally, in 2014, the 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 and in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing. Moreover, 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. However, in June 2016, a Wyoming federal judge struck down this final rule, finding that the BLM lacked authority to promulgate the rule, the BLM appealed the decision to the U.S. Circuit Court of Appeals in July 2016, the appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rulemaking to rescind the 2015 rule and, in December 2017, the BLM published a final rule rescinding the March 2015 rule. In January 2018, litigation challenging the BLM's rescission of the 2015 rule was brought in federal court.

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. 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.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to added delays for our operations or increased operating costs in our production of oil and natural gas. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, which could have a material adverse effect on our business or results of operations.

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 Texas, where the Company conducts operations, as well as Oklahoma, Kansas, Colorado, New Mexico, and Arkansas as the states with the most significant hazards from induced seismicity.

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 has issued rules for produced water disposal wells 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 has adopted similar rules for the permitting of produced water disposal wells. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. 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 natural gas the Company produces.

Climate change continues to attract considerable public, governmental 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. However, the EPA has determined that emissions of GHGs present an endangerment to public health and the environment and has adopted regulations under existing provisions of the CAA that establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for 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. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rules with the New Source Performance Standards ("NSPS").

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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, and any other new methane emission standards imposed on the oil and natural gas sector could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. 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"). While this international agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. The Paris Agreement was signed by the United States in April 2016 and entered into force in November 2016. However, in August 2017, the U.S. State Department informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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 natural gas the Company produces. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time.

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 natural 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 and produced water 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 natural 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 natural 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 natural 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 natural gas business is subject to extensive governmental regulation under which, among other things, rates of production from oil and natural 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 natural gas exploration, production and development operations are subject to stringent federal, 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 published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" and is expected to issue non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule in the first half of 2018. In a second example, in June 2015, the EPA and U.S. Army Corps of Engineers ("Corps") published a final rule that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, including wetlands, but legal challenges to this rule followed. The 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the U.S. Supreme Court agreed to hear the case. The EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, announced their intent to issue a new rule defining the Clean Water Act's jurisdiction, and published a proposed rule in November 2017 specifying that the contested June 2015 rule would not take effect until two years after the November 2017 proposed rule was finalized and published in the Federal Register. Recently, on January 22, 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the 2015 rule currently remains stayed, the previously-filed district court cases will be allowed to proceed. As a result of these recent developments, future implementation of the June 2015 rule is uncertain at this time. 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, in response to a lawsuit filed in the U.S. District Court for the District of Columbia 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.

The Endangered Species Act and other restrictions intended to protect certain species of wildlife govern our oil and natural gas operations, which constraints could have an adverse impact on our ability to expand some of our existing operations or limit our ability to explore for and develop new oil and natural gas wells.

The federal Endangered Species Act ("ESA") and comparable state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migrating birds under the federal Migratory Bird Treaty Act. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species and, in these areas, we may be obligated to develop and implement plans to avoid potential adverse effects to protected species and their habitats, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of one or more settlements approved by the U.S. Fish and Wildlife Service, the agency is required to make determinations on the listing of numerous species as endangered or threatened under the ESA pursuant to specific timelines. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures, time delays or limitations on our exploration and production activities, which costs, delays or limitations could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

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

Numerous executive, legislative and regulatory proposals affecting the oil and natural 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 natural 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 Pipeline and Hazardous Materials Safety Administration ("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.

Recently enacted changes to the U.S. federal tax laws could adversely affect our financial position, results of operations and cash flows.

Legislation recently enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act, made significant changes to U.S. tax laws. The Tax Cuts and Jobs Act (i) eliminates the deduction for certain domestic production activities, (ii) imposes new limitations on the utilization of net operating losses, (iii) eliminates the exception under Section 162(m) for qualified performance-based compensation, (iv) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and natural gas companies. While past legislative proposals have included changes to certain key U.S. federal income tax provisions currently available to oil and natural gas companies, including (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, and (iii) an extension of the amortization period for certain geological and geophysical expenditures, these specific changes are not included in the Tax Cuts and Jobs Act. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. This legislation or any future similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to natural gas and oil exploration and production. We continue to examine the impact the Tax Cuts and Jobs Act may have on us, and it could have an adverse effect on our financial position, results of operations and cash flows.

Our ability to deduct interest expense incurred in our business may be limited.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for “business interest” is limited to the sum of our business interest income and 30% of our “adjusted taxable income.” For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Our ability to deduct compensation paid to certain employees may be limited.

Section 162(m) of the Code limits our ability to deduct certain compensation paid to covered employees (i.e., individuals currently serving or who have previously served, at any point after December 31, 2016, as the Chief Executive Officer, Chief Financial Officer and the three other highest compensated officers of the Company). Previously, Section 162(m) provided an exception for certain qualified performance-based compensation; however, the Tax Cuts and Jobs Act eliminates this exception (other than for compensation provided under certain grandfathered arrangements), and as a result, our ability to deduct certain amounts paid to our covered employees may be limited.

Legal proceedings could result in liability affecting our results of operations.

Most oil and natural 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 natural 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.

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

Upon our emergence from bankruptcy in 2016, we adopted fresh start accounting. Accordingly, our financial conditions and results of operations subsequent to emergence from bankruptcy are not comparable to the financial condition or results of operations reflected in the Company's historical financial statements prior to our emergence from bankruptcy. Investors may find it more difficult to analyze the performance of the Company due to the limited comparable historical financial information.

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 a 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 veto rights of the parties to the director nomination agreement apply to the following transactions:

- 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.

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.
Completion - Preparation of a well bore and installation of permanent equipment for production of oil, natural gas or NGLs or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.
Condensate - Liquid hydrocarbons that are found in natural gas wells and condense when brought to the well surface. Condensate is used synonymously with oil.
Differential - An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
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.
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.
Field - An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
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.
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.
NYMEX - The New York Mercantile Exchange.
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.

Reserves - Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

Reservoir - A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spot Market Price - The cash market price without reduction for expected quality, transportation and demand adjustments.

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.

WTI - West Texas Intermediate.

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, year ended December 31, 2017 and the period of April 23, 2016 through December 31, 2016

The trading price of our common stock prior to our emergence from bankruptcy is not comparable to our successor Company and therefore excluded from the table below. Our common stock, was quoted on the OTCQX Market under the symbol “SWTF” from April 23, 2016 through May 4, 2017. On May 5, 2017 our common stock began trading on the New York Stock Exchange under the symbol “SBOW”. The high and low quarterly closing sale prices for the common stock for the year ended December 31, 2017 and the period of April 23, 2016 through December 31, 2016 were as follows:

	2017				2016		
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Period of April 23, 2016 through June 30, 2016	Third Quarter	Fourth Quarter
Low	$25.50	$24.00	$19.89	$21.53	$22.00	$24.40	$26.77
High	$34.00	$31.33	$27.05	$29.99	$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 May 4, 2017 were $35.70 and $22.00, respectively. The high and low closing sale prices for the common stock reported on the New York Stock Exchange for the period of May 5, 2017 through December 31, 2017 were $31.33 and $19.89, respectively.

Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our credit agreements.

We had approximately 103 stockholders of record as of December 31, 2017.

Stock Repurchase Table

The following table summarizes repurchases of our common stock during the fourth quarter of 2017, 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, 2017	—	$ —	—	$---
November 1- 30, 2017	7,212	$ 22.06	—	—
December 1 - 31, 2017	—	$ —	—	—
Total	7,212	$ 22.06	—	$---

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, 2017 see Note 7 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: Year Ended December 31, 2017	Successor: April 23, 2016 - December 31, 2016	Predecessor: January 1, 2016 - April 22, 2016	Predecessor: Years Ended December 31, 2015	Predecessor: Years Ended December 31, 2014	Predecessor: Years Ended December 31, 2013
Oil and Gas Sales	$ 195,910	$ 121,386	$ 43,027	$ 246,270	$ 547,790	$ 585,229
Income (Loss) Before Income Taxes	$ 70,017	$ (156,288)	$ 851,611	$ (1,734,514)	$ (433,470)	$ 198
Net Income (Loss)	$ 71,971	$ (156,288)	$ 851,611	$ (1,653,971)	$ (283,427)	$ (2,442)
Net Cash Provided by (Used in) Operating Activities	$ 107,838	$ 47,427	$ (41,466)	$ 42,274	$ 306,371	$ 311,447
Per Share and Share Data						
Weighted Average Shares Outstanding - Basic	11,453	10,013	44,692	44,463	43,795	43,331
Earnings (loss) per Share - Basic	$ 6.28	$ (15.61)	$ 19.06	$ (37.20)	$ (6.47)	$ (0.06)
Earnings (loss) per Share - Diluted	$ 6.25	$ (15.61)	$ 18.64	$ (37.20)	$ (6.47)	$ (0.06)
Production (Bcfe equivalent)	56.1	38.2	16.8	66.9	69.6	68.4
Average Sales Price [(1)]						
Natural Gas (per Mcf produced)	$ 3.03	$ 2.55	$ 1.96	$ 2.56	$ 4.36	$ 3.66
Natural Gas Liquids (per barrel)	$ 21.61	$ 16.39	$ 11.04	$ 14.54	$ 31.83	$ 31.39
Oil (per barrel)	$ 50.98	$ 44.79	$ 31.43	$ 47.11	$ 92.74	$ 103.42
Mcfe Equivalent	$ 3.49	$ 3.18	$ 2.55	$ 3.68	$ 7.87	$ 8.72

(1) These prices do not include the effects of our hedging activities which were recorded in " Net gain (loss) on commodity derivatives" on the consolidated statements of operations included in this Form 10-K.

Balance Sheet Data	Successor December 31, 2017	Successor December 31, 2016	Predecessor December 31, 2015	Predecessor December 31, 2014	Predecessor December 31, 2013
Assets					
Current Assets	$ 42,569	$ 21,479	$ 61,847	$ 64,669	$ 92,489
Property & Equipment, Net of Accumulated Depreciation, Depletion, Amortization and Impairment	495,397	347,195	457,903	2,095,037	2,588,817
Total Assets	551,270	377,299	524,998	2,173,347	2,698,505
Liabilities					
Current Liabilities (1)	75,497	79,124	333,053	148,919	176,033
Long-Term Debt (1)	265,325	198,000	—	1,074,534	1,142,368
Total Liabilities	357,812	301,244	1,377,722	1,378,969	1,633,155
Stockholders' Equity (Deficit)	$ 193,458	$ 76,055	$ (852,724)	$ 794,378	$ 1,065,350
Shares Outstanding at Year-End	11,571	10,054	44,592	43,918	43,402
Book Value per Share at Year-End	$ 16.72	$ 7.56	$ (19.12)	$ 18.09	$ 24.55
Additional Information					
Producing Wells					
SilverBow Operated	694	774	1,030	1,040	1,039
Outside Operated	15	5	26	25	25
Total Producing Wells	709	779	1,056	1,065	1,064
Wells Drilled (Gross)	25	7	24	36	48
Proved Reserves					
Natural Gas (Bcf) (2)	842.7	626.8	311.7	686.7	815.1
Oil Reserves (MBoe) (2)	7.2	5.8	10.1	49.7	53.0
NGL Reserves (MBoe) (2)	23.1	13.7	8.2	29.7	30.4
Total Proved Reserves (MMcfe equivalent)	1,024.4	744.0	421.6	1,163.0	1,315.2

(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 Prior First Lien 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 surrounding the availability of the financing that would be necessary to develop our proved undeveloped reserves, due in part to our bankruptcy filing.

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 year ended December 31, 2017 (successor), 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) included in this Form 10-K. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 53 of this report.

As discussed in Notes 12 and 13 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

SilverBow Resources is a growth oriented independent oil and gas company headquartered in Houston, Texas. The Company's strategy is focused on acquiring and developing assets in the Eagle Ford Shale located in South Texas where we have assembled over 100,000 net acres across five operating areas. Our acreage positions in each of our operating areas are highly contiguous and designed for optimal and efficient horizontal well development. We have built a balanced portfolio of properties with a significant base of current production and reserves coupled with low-risk development drilling opportunities and meaningful upside from newer areas. We produced an average 177 MMcfe per day during the fourth quarter of 2017 and had proved reserves of 1,024 MMcfe (82% natural gas) with a PV-10 of $805 million as of December 31, 2017. 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 most directly comparable GAAP measure.

Being a committed and long-term operator in South Texas, the Company possesses a significant understanding of the reservoir characteristics, geology, landowners, and competitive landscape in the region. We leverage this in-depth knowledge to continue to assemble high quality drilling inventory while continuously enhancing our operations to maximize returns on capital invested.

We have transformed the Company from a conventional, Louisiana shallow water producer to a focused Eagle Ford player. Over the last few years we have successfully renegotiated midstream contracts, moved our headquarters to west Houston, and reduced headcount over 50% since 2015. These initiatives have resulted in a reduction of per unit G&A from $0.64/Mcfe at year end 2015 to $0.53/Mcfe at year end 2017, a 17% reduction. We expect to continue improving our G&A metrics as we execute on our strategic growth program. We continue to refine our portfolio, including the sale of AWP Olmos wells on March 1, 2018. This strategic divestiture allows us to better leverage existing personnel while lowering field-level costs on a per unit basis. We believe there are other opportunities to continue streamlining our business to extract value for our shareholders.

Operational Results

The Company continues to optimize completion techniques in order to enhance well performance across its portfolio, including optimized landing points, frac designs, and the expanded use of diverters and scale inhibitors. The following table and discussion outlines our drilling and completion schedule for 2017 and our initial plans for 2018:

Fields	Acreage	2017 Production (MMcfe/d)	% Gas	2017 Wells Drilled	2017 Wells Completed
Artesia	12,811	20,256	44%	7	7
AWP	42,566	35,628	53%	2	2
Fasken	7,718	92,518	100%	6	10
Other (1)	37,026	5,392	96%	3	3
Total	**100,121**	**153,794**	**82%**	**18**	**22**

(1) Other includes Oro Grande, Uno Mas and other non-core properties.

In Fasken, the Company tested an optimized new completion design in the Upper Eagle Ford in mid-2017 with encouraging results. As a result, the Company drilled a six well pad in late 2017 that was completed in the first quarter of 2018 which included three Upper Eagle Ford wells and three lower Eagle Ford wells. The Company plans to drill six net Upper Eagle Ford wells and seven net Lower Eagle Ford wells in 2018. In 2017, the Company added 2,520 net acres near Fasken.

In Oro Grande where the Company holds just under 25,000 net acres, the Company drilled and completed two assessment wells during 2017; the NMC 1H and NMC 2H. The NMC 1H had cumulative production of 0.9 Bcfe after 90 producing days, while the NMC 2H had cumulative production of 0.8 Bcfe after 90 producing days. Based upon the results of these two initial wells in this acreage block, the Company plans on drilling and completing five additional net wells in Oro Grande during 2018.

The Company returned to Artesia for the first time since 2013 in the second and third quarters to deploy the newest generation of drilling and completion technology. Earlier wells in this area were drilled without the benefit of processed and evaluated 3D seismic, target window identification, and modern completion design tied to longer laterals. The Company completed seven wells in northern Artesia in 2017, with lateral lengths ranging from 6,000 feet to 11,000 feet in accordance with lease configurations. Drilling costs averaged $2.0 million per well for the seven wells drilled in Artesia during the second and third quarters, a decrease of 38% from our 2013 drilling program. Likewise, the average completion cost per stage of $0.1 million decreased 33% despite increasing proppant volumes by 62% compared to our average completions in 2013. The Company is currently leasing acreage in the northern portion of Artesia to increase the amount of high quality inventory where future capital will be deployed.

In AWP, SilverBow drilled and completed two gas wells in 2017, the Bracken 21H and 22H, which utilized 300 foot frac stage spacing and 1,500 pounds of proppant per foot of lateral. The Company continues to optimize its development of the AWP area to provide higher recovery efficiencies and enhanced economic returns. These objectives will be achieved through reservoir pressure management practices and optimized spacing and drilling sequencing between parent and child wells. During 2017, the Company acquired roughly 21,000 acres in AWP. The Company continues to acquire bolt-on acreage in this area to further enhance efficiencies and returns while leveraging existing infrastructure. The Company plans on drilling seven net wells in this area in 2018, including two net wells in the Company’s oily acreage in Northern AWP.

On November 6, 2017 the Company purchased the non-operating working interest of two joint interest partners in certain wells and leases in AWP Field. The value of these assets are concentrated in proved oil and gas reserves. This purchase constitutes a business combination. The acquisition cost of this interest was $9.4 million. Additionally, the Company assumed asset retirement obligations of $0.2 million.

Strategic dispositions: Effective July 31, 2017, the Company disposed of its Wheeler assets in South Texas. This package represented 117 wellbores in the Company’s AWP Olmos area. We received net proceeds of $0.7 million and the buyer assumed approximately $0.5 million of plugging and abandonment liability. No gain or loss was recorded on the sale of this property.

Effective December 22, 2017, we closed the sale of the Company's wellbores and facilities of our Bay De Chene field located in Louisiana. The contract price of $16.3 million will be paid by the Company, as seller. The payments will be funded over time, through an escrow account, with funds being released as plugging and abandonment work is performed and certified to meet state requirements. The buyer assumed approximately $20.9 million of plugging and abandonment liability with no gain or loss recorded on the sale of this property. Of the $16.3 million, during the first quarter of 2018 approximately $6.0 million was released in the first quarter of 2018 for completion of initial post-closing requirements. The remaining $10 million will be funded as the abandonment work is completed and certified. Based on the available information, it is unlikely that more than half of the $10 million allocation will be funded before the end of 2018. Accordingly, the initial allocation of the accrued liability will be $11.3 million as a current liability and $5 million as a non-current liability.

Additionally, subsequent to the year ended December 31, 2017, the Company executed a definitive purchase and sale agreement to divest certain wells in its AWP Olmos field for $28.8 million plus the assumption by the buyer of $6.2 million of asset retirement obligations. This transaction closed on March 1, 2018 and has an effective date of January 1, 2018. These assets are located in McMullen County, Texas and include roughly 491 wells with total proved reserves of 28 Bcfe (100% proved developed) as of December 31, 2017. Full year 2017 production from these properties was approximately 9.5 Mmcfe/d (57% natural gas). Cash proceeds from the sale will be used to repay outstanding borrowings under the Company’s Credit Facility. The Company anticipates that its borrowing base will remain unchanged at $330 million after closing this transaction and will be reviewed as normal during its regularly scheduled Spring redetermination.

2017 cost reduction initiatives: We continue to focus on cost efficient operations and took additional actions in 2017 to reduce operating and overhead costs. These initiatives include field staff reductions, intermittent production of marginal properties, disposition of uneconomic and higher cost properties, full utilization of existing facilities, elimination of redundant equipment and replacement of rental equipment with company-owned equipment. We have also improved each step in the process of drilling and completing a well. Our procurement team takes a diligent and systematic approach to reducing the total delivered costs of purchased services by examining costs at their most detailed level. Services are commonly sourced directly from the suppliers. This has led to a significant reduction in our overall lease operating expenses at the field level. For example, our South Texas lease operating expenses were $0.40 per million cubic feet of natural gas equivalent ("Mcfe") for the full year 2017 compared to $0.96 per MMcfe in 2013.

Additionally, our significant operational control, as well as our manageable leasehold obligations, provide us the flexibility to control our costs as we transition to a development mode across our portfolio. At the corporate level, we have also undergone additional staff reductions, reduced the square footage of leased office space and are taking additional steps to further reduce overhead costs. This has led to a decline in our net cash general and administrative costs of $23.2 million in 2017 compared to $35.3 million in 2015.

We have continued to maintain a safe working environment while implementing these cost-reduction efforts. Our corporate total recordable incident rate ("TRIR") declined from 1.8 incidents per 200,000 work hours in 2016 to 0.2 in 2017.

Management Changes

The Company announced the appointment of Sean Woolverton as Chief Executive Officer, effective March 1, 2017. He also serves as a member of the Board of Directors. Mr. Woolverton succeeded the Company's interim Chief Executive Officer, Bob Banks, who continued to serve at the Company until his departure on November 3, 2017. Mr. Woolverton was previously the Chief Operating Officer of Samson Resources Company, which he joined in November 2013. From 2007 to 2013, Mr. Woolverton held a series of positions of increasing responsibility at Chesapeake Energy Corporation, a public independent exploration and development oil and natural gas company, including Vice President of its Southern Appalachia business unit. Prior to joining Chesapeake Energy Corporation, Mr. Woolverton worked for Encana Corporation, a North American oil and natural gas producer, where he oversaw its Fort Worth Basin development and shale exploration teams in North Texas. Earlier in his career, Mr. Woolverton worked for Burlington Resources in multiple engineering and management roles. Mr. Woolverton received his Bachelor of Science degree in Petroleum Engineering from Montana Tech.

The Company announced the appointment of Gleeson Van Riet as Executive Vice President and Chief Financial Officer, effective March 20, 2017. Mr. Van Riet succeeded Alton Heckaman, who announced his retirement in August 2016. Mr. Van Riet was previously the Chief Financial Officer of Sanchez Energy Corporation where he held a series of positions of increasing responsibility from April 2013 to March 2016. Mr. Van Riet has over 20 years of finance experience and previously worked as an investment banker with Credit Suisse and Donaldson, Lufkin & Jenrette in London and Los Angeles. Mr. Van Riet earned a dual B.A. and B.S. from the University of Pennsylvania and an MBA from the Harvard Business School.

The Company announced the appointment of Chris Abundis as Senior Vice President and General Counsel, effective March 22, 2017. From April 2016 to March 2017, Mr. Abundis was Vice President, General Counsel and Secretary for the Company. He has also served the Board of Directors as Secretary of the Company, a position that he has held since August 2012. From February 2007 to August 2012, Mr. Abundis served as Assistant Secretary of the Company and has provided legal consultation in corporate governance, securities law and other corporate related matters in progressive positions of responsibility including Senior Counsel, Counsel and Associate Corporate Counsel. Mr. Abundis received a Bachelor of Business Administration and Master of Science in Accounting from Texas A&M University and a Juris Doctor from South Texas College of Law.

The Company announced the appointment of Steven W. Adam as Executive Vice President and Chief Operating Officer, effective November 6, 2017, succeeding Robert J. Banks. Steve Adam was previously the Senior Vice President of Operations of Sanchez Oil & Gas where he held a series of positions of increasing responsibility from April 2013 to July 2017. Mr. Adam has over 40 years of upstream exploration and production and petroleum services experience with both major and independent companies. His unconventional resource management experiences have been with Occidental Petroleum and most recently with Sanchez Oil & Gas. Mr. Adam received his Bachelor of Science degree in Chemical Engineering from Montana State University, Master of Business Administration from Pepperdine University and Advanced Management Certificate from the University of California - Berkeley.

Leasing Activity

The Company expanded its Eagle Ford shale footprint by over 50% in 2017, through a combination of grassroots leasing and strategically acquiring bolt-on producing acreage. The Company spent approximately $50 million on acquiring over 35,000 acres, primarily throughout the gas and rich gas windows of the Eagle Ford shale. Specifically, the Company added approximately 21,463 acres at AWP in McMullen County, 9,548 acres at Uno Mas in Live Oak County, 3,066 acres at Artesia in La Salle County, and 2,520 acres at Fasken in Webb County.

2017 Liquidity and Capital Resources

Our primary use of cash flow has been to fund capital expenditures to develop our oil and gas properties. As of December 31, 2017, the Company's liquidity consisted of approximately $7.8 million of cash-on-hand and $253.6 million in available borrowings (calculated as $257 million of borrowing availability less $3.4 million in letters of credit) on our $330 million borrowing base. Management believes the Company has sufficient liquidity to meet its obligations for at least the next twelve months and execute our long-term development plans.

Revolving Credit Facility and Prior First Lien Credit Agreement. Upon emergence from bankruptcy the Company entered into a Senior Secured Revolving Credit Agreement among the Company as borrower, JPMorgan Chase Bank, National Association as administrative agent, and certain lenders party thereto. On April 19, 2017, the Company amended and restated the Senior Secured Revolving Credit Agreement by entering into a First Amended and Restated Senior Secured Revolving Credit Agreement (the "Credit Agreement") among the Company as borrower, JPMorgan Chase Bank, N.A. as administrative agent, and certain lenders that are a party thereto, which provides for revolving loans of up to the borrowing base then in effect (the "Credit Facility"). The Credit Facility matures on April 19, 2022. The maximum credit amount under the Credit Facility is currently $600 million with a borrowing base of $330 million. The borrowing base is scheduled to be redetermined in May and November of each calendar year and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Company and the administrative agent may request an unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $25 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

Interest under the Credit Facility accrues at the Company's option either at an Alternative Base Rate plus the applicable margin ("ABR Loans") or the LIBOR Rate plus the applicable margin ("Eurodollar Loans"). The applicable margin ranges from 1.75% to 2.75% for ABR Loans and 2.75% to 3.75% for Eurodollar Loans. The Alternate Base Rate and LIBOR Rate are defined, and the applicable margins are set forth, in the Credit Agreement. Undrawn amounts under the Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The obligations under the Credit Agreement 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 85% of estimated proved reserves of the Company and its subsidiaries.

The Credit Agreement contains the following financial covenants:

- a ratio of total debt to EBITDA, as defined in the Credit Agreement, for the most recently completed four fiscal quarters, not to exceed 4.0 to 1.0 as of the last day of each fiscal quarter; and

- a current ratio, as defined in the Credit Agreement, and which includes in the numerator available borrowings undrawn under the borrowing base, of not less than 1.0 to 1.0 as of the last day of each fiscal quarter.

Additionally, the Credit Agreement contains certain representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

We are in compliance with the covenants as of December 31, 2017 and expect to be in compliance with the covenants under the Credit Agreement during the next twelve months. Maintaining or increasing our borrowing base under our 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.

Senior Secured Second Lien Notes. On December 15, 2017, the Company entered into a note purchase agreement for Senior Secured Second Lien Notes (the “Second Lien”) among the Company as issuer, U.S. Bank National Association as agent and collateral agent (the “Second Lien Agent”), and certain holders that are a party thereto, and issued notes in an initial principal amount of $200 million, with a $2.0 million discount, for net proceeds of $198.0 million (the “Second Lien Facility”). The Company has the ability, subject to the satisfaction of certain conditions (including compliance with the Asset Coverage Ratio described below and the agreement of the holders to purchase such additional notes), to issue additional notes in a principal amount not to exceed $100 million. The Second Lien matures on December 15, 2024.

Interest under the Second Lien is payable quarterly and accrues at LIBOR plus 7.5%; provided that if LIBOR ceases to be available, the Second Lien provides for a mechanism to use ABR (an alternate base rate) plus 6.5% as the applicable interest rate. The definitions of LIBOR and ABR are set forth in the Second Lien. To the extent that a payment, insolvency or, at the holders’ election, another default exists and is continuing, all amounts outstanding under the Second Lien will bear interest at 2.0% per annum above the rate and margin otherwise applicable thereto. Additionally, to the extent the Company were to default on the Second Lien, this would potentially trigger a cross-default on our Credit Facility.

The Company has the right, to the extent permitted under the Credit Facility and subject to the terms and conditions of the Second Lien, to optionally prepay the notes issued pursuant to the Second Lien, subject to the following repayment fees: during years one and two, a customary “make-whole” amount (which is equal to the present value of the remaining interest payments through the twenty-four month anniversary of the issuance of the Second Lien, discounted at a rate equal to the Treasury Rate plus 50 basis points) plus 2.0% of the principal amount of the notes repaid; during year three, 2.0% of the principal amount of the notes being prepaid; during year four, 1.0% of the principal amount of the notes being prepaid; and thereafter, no premium. Additionally, the Second Lien contains customary mandatory prepayment obligations upon asset sales (including hedge terminations), casualty events and incurrences of certain debt, subject to, in certain circumstances, reinvestment periods. Management has deemed the probability of mandatory prepayment due to default is remote.

The obligations under the Second Lien are secured, subject to certain exceptions and other permitted liens (including the liens created under the Credit Facility), by a perfected security interest, second in priority to the liens securing our Credit Facility, and mortgage lien on substantially all assets of the Company and certain of its subsidiaries, including a mortgage lien on oil and gas properties attributed with at least 85% of estimated PV-9 of proved reserves of the Company and its subsidiaries and 85% of the book value attributed to the PV-9 of the non-proved oil and gas properties of the Company. PV-9 is determined using commodity price assumptions provided by the Administrative Agent of the Credit Facility.

The Second Lien contains an Asset Coverage Ratio, which is only tested (i) as a condition to issue additional notes and (ii) in connection with certain asset sales in order to determine whether the proceeds of such asset sale must be applied as a prepayment of the notes and includes in the numerator the PV-10 (defined below), based on forward strip pricing, plus the swap mark-to-market value of the commodity derivative contracts of the Company and its restricted subsidiaries and in the denominator the total net indebtedness of the Company and its restricted subsidiaries, of not less than 1.25 to 1.0 as of each date of determination (the “Asset Coverage Ratio Requirement”). PV-10 value is 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%.

The Second Lien also contains a financial covenant measuring the ratio of total net debt to EBITDA, as defined in the purchase agreement, for the most recently completed four fiscal quarters, not to exceed 4.5 to 1.0 as of the last day of each fiscal quarter.

The Second Lien contains certain customary representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Second Lien contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Second Lien Facility to be immediately due and payable.

The debt was issued at a 1% discount of $2.0 million and the Company incurred $5.7 million in debt issuance costs. As of December 31, 2017, net amounts recorded for the Second Lien were $192.3 million, net of unamortized debt discount and debt issuance costs.

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.

Summary of 2017 Financial Results

- *Revenues and net income (loss):* The Company's oil and gas revenues were $195.9 million for the year ended December 31, 2017 (successor) and $121.4 million and $43.0 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. Revenues were higher primarily due to overall higher commodity pricing as well as higher natural gas production, partially offset by lower oil and NGL production. The Company's net income of $72.0 million for the year ended December 31, 2017 (successor) was primarily due to higher commodity pricing along with lower operating expenses 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 and the 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.

- *Capital expenditures:* The Company's capital expenditures on a cash basis were $193.0 million for the year ended December 31, 2017 (successor) compared to $45.7 million and $24.5 million in the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. The expenditures for the year ended December 31, 2017 (successor), were primarily driven by development activity in our Fasken, AWP, Artesia and Oro Grande fields in Eagle Ford. Capital expenditures in the period of April 23, 2016 through December 31, 2016 (successor) were focused on drilling and completion activities in our Fasken field. These expenditures were funded by operating cash flows and proceeds from property dispositions. Expenditures for the period of January 1, 2016 through April 22, 2016 (predecessor), 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.

- *Working capital:* The Company had a working capital deficit of $32.9 million at December 31, 2017 and a deficit of $57.6 million at December 31, 2016. The working capital computation does not include available liquidity through our Credit Facility.

- *Cash Flows:* For the year ended December 31, 2017 (successor) the Company generated cash from Operating Activities of $107.8 million, of which $0.7 million was attributable to changes in working capital. Cash used for property additions was $193.0 million. This included $9.9 million attributable to a net increase of capital related payables and accrued costs. The Company’s net payments on the revolving Credit Facility were $125.0 million which includes the pay down on Credit Facility borrowings with proceeds from the Second Lien.

  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 $11.2 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 the revolving Credit Facility 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 $15.4 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 Prior First Lien 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.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter are shown below as of December 31, 2017 (in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Non-cancelable operating leases [1]	$ 4,622	$ 698	$ 627	$ 263	$ —	$ —	$ 6,210
Asset retirement obligation [2]	2,109	873	635	130	78	6,960	10,785
Drilling, Completion and Geoscience Contracts	4,082	—	—	—	—	—	4,082
Gas transportation and Processing [3]	6,816	8,410	7,479	325	—	—	23,030
Interest Cost [4]	22,415	22,498	22,589	22,690	20,410	38,304	148,906
Long-Term Debt	—	—	—	—	73,000	200,000	273,000
Executive severance agreements	1,552	554	—	—	—	—	2,106
Other contractual commitments [5]	11,250	5,000	—	—	—	—	16,250
Total	$ 52,846	$ 38,033	$ 31,330	$ 23,408	$ 93,488	$ 245,264	$ 484,369

(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 6 of the consolidated financial statements in this Form 10-K.
(2) Amounts shown by year are the net present value at December 31, 2017.
(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 the weighted average interest rate during the quarter ended December 31, 2017 on our Credit Facility of 4.7%, see Note 4 of these consolidated financial statements in this Form 10-K. Actual interest rate is variable over the term of the facility.
(5) Obligation under Bay De Chene sales contract.

As of December 31, 2017, we had no off-balance sheet arrangements requiring disclosure pursuant to article 303(a) of Regulation S-K.

Proved Oil and Gas Reserves

During 2017, our reserves increased by approximately 280.7 MMcfe due to increases in our natural gas reserves primarily from our AWP, Fasken and Oro Grande fields. As of December 31, 2017, 45% of our total proved reserves were proved developed, compared with 51% at year-end 2016 and 80% at year-end 2015.

At December 31, 2017, our proved reserves were 1,024.4 MMcfe with a Standardized Measure of $732 million, which is an increase of approximately $327 million, or 80%, from the prior year-end levels. In 2017, our proved natural gas reserves increased 215.9 MMcf, or 34%, while our proved oil reserves increased 1.4 MMBbl, or 24%, and our NGL reserves increased 9.4 MMBbl, or 69%, for a total equivalent increase of 280.7 MMcfe, or 38%.

We have added proved reserves primarily through our drilling activities, including 317.0 MMcfe added in 2017. 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 4.9 MMcfe of reserves during 2017 in conjunction with our dispositions, as described further in Note 9 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 2017 was $2.95 per Mcf. This average price increased from the average price of $2.43 per Mcf used for 2016. Our average oil price used in the calculation for 2017 was $50.38 per Bbl. This average price increased from the average price of $41.07 per Bbl used in the calculation for 2016.

Results of Operations

Revenues — Year Ended December 31, 2017 (successor), 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)

The tables included below set forth financial information for the year ended December 31, 2017, 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) which are distinct reporting periods as a result of our emergence from bankruptcy on April 22, 2016.

2017 - Our oil and gas sales in 2017 increased by 19% compared to revenues in 2016, primarily due to overall higher commodity pricing and higher natural gas volumes, offset by lower oil and NGL volumes. Average oil prices we received were 29% higher than those received during 2016, while natural gas prices were 27% higher and NGL prices were 48% higher.

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% higher, and NGL prices were flat.

Crude oil production was 7%, 12%, 19% and 22% of our production volumes while crude oil sales revenues were 18%, 29%, 38% and 46% of oil and gas sales revenue for the year ended December 31, 2017 (successor), 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. Natural gas production was 82%, 76%, 68% and 66% of our production volumes while natural gas sales revenues were 71%, 61%, 52%, and 46% of oil and gas sales for the year ended December 31, 2017 (successor), 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 following tables provide information regarding the changes in the sources of our oil and gas sales and volumes for the year ended December 31, 2017 (successor), 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):

Fields	Oil and Gas Sales (In Millions)			
	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Artesia	$ 33.2	$ 9.9	$ 3.5	$ 19.3
AWP	55.2	42.4	14.7	87.1
Fasken	101.8	53.0	14.3	72.1
Other (1)	5.7	16.1	10.5	67.8
Total	$ 195.9	$ 121.4	$ 43.0	$ 246.3

(1) For 2016 and 2015, primarily fields sold during the year including our former Lake Washington, South Bearhead Creek and Burr Ferry fields. For 2017, primarily from our Oro Grande and Uno Mas fields.

Fields	Net Oil and Gas Production Volumes (Mcfe)				
	Successor		Predecessor		
		(a)	(b)	(a) + (b)	
	Year Ended December 31, 2017	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
Artesia	7,393	2,904	1,542	4,446	6,288
AWP	13,004	11,880	5,706	17,586	21,708
Fasken	33,769	20,772	7,278	28,050	28,614
Other (1)	1,969	2,634	2,316	4,950	10,266
Total	56,135	38,190	16,842	55,032	66,876

(1) For 2016 and 2015, primarily fields sold during the year including our former Lake Washington, South Bearhead Creek and Burr Ferry fields. For 2017, primarily from our Oro Grande and Uno Mas fields.

Our production increase from 2016 to 2017 was primarily due to increased natural gas production and increased drilling and completion activity, partially offset by strategic dispositions of our non-core fields during 2016.

In 2017, our $31.5 million, or 19% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $44.6 million favorable impact on sales, with an increase of $29.3 million due to the 27% increase in natural gas prices received, an increase of $7.9 million due to the 29% increase in oil prices received and an increase of $7.4 million due to the 48% increase in NGL prices received.
- Volume variances that had a $13.1 million unfavorable impact on sales, with a $24.6 million decrease due to the 0.6 million Bbl decrease in oil production volumes, a $12.4 million increase due to the 5.2 Bcf increase in natural gas production volumes and a $0.9 million decrease due to the 0.1 million Bbl decrease in NGL production volumes.

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.

The following table provides additional information regarding our oil and gas sales, by commodity type, for the year ended December 31, 2017 (successor), 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):

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
2017 (Successor)							
First Quarter	146	204	10.1	12.2	$49.26	$20.33	$3.07
Second Quarter	139	228	11.1	13.3	$46.82	$18.49	$3.16
Third Quarter	170	267	11.7	14.3	$46.93	$21.67	$3.01
Fourth Quarter	229	347	12.8	16.3	$57.64	$24.37	$2.88
Total	684	1,046	45.7	56.1	$50.98	$21.61	$3.03
2016 (Successor)							
April 23 - June 30	254	246	8.1	11.1	$44.35	$14.15	$1.97
Third Quarter	292	255	11.5	14.8	$43.27	$16.38	$2.71
Fourth Quarter	240	226	9.5	12.3	$47.10	$18.84	$2.86
Total	786	727	29.1	38.2	$44.79	$16.39	$2.55
2016 (Predecessor)							
First Quarter	427	310	9.2	13.6	$30.07	$10.83	$1.98
April 1 - April 22	95	70	2.2	3.2	$37.49	$11.96	$1.90
Total	522	380	11.4	16.8	$31.43	$11.04	$1.96
2015 (Predecessor)							
First Quarter	685	426	10.7	17.4	$45.10	$16.09	$2.76
Second Quarter	628	366	10.4	16.4	$56.65	$15.18	$2.61
Third Quarter	581	344	10.8	16.4	$45.24	$12.94	$2.70
Fourth Quarter	511	297	11.9	16.7	$40.22	$13.38	$2.20
Total	2,405	1,433	43.8	66.9	$47.11	$14.54	$2.56

For the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the year ended December 31, 2015 (predecessor), we recorded net gains (losses) of $17.9 million, ($19.7) million and $0.2 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

The following table provides additional information regarding our expenses for the year ended December 31, 2017 (successor), 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):

	Successor		Predecessor	
Costs and Expenses	**Year Ended December 31, 2017**	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**	**Year Ended December 31, 2015**
General and administrative, net	$ 30,000	$ 22,538	$ 9,245	$ 42,611
Depreciation, depletion, and amortization	46,933	36,436	20,439	177,512
Accretion of asset retirement obligation	2,322	2,878	1,610	5,572
Lease operating cost	21,908	25,777	14,933	70,188
Transportation and gas processing	19,360	13,038	6,090	21,741
Severance and other taxes	8,205	6,713	3,917	17,090
Interest expense, net	15,070	15,310	13,347	75,870
Write-down of oil and gas properties	—	133,496	77,732	1,562,086
Reorganization items, net	—	1,639	(956,142)	6,565
Total Costs and Expenses	$ 143,798	$ 257,825	$ (808,829)	$ 1,979,235

2017 - Our costs and expenses during 2017 versus 2016 were as follows:

Lease Operating Cost. These expenses on a per Mcfe basis were $0.39, $0.67 and $0.89 for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. The decreases in the successor periods were primarily due to lower labor, compression, utilities, maintenance, chemicals and transportation costs primarily driven by concentrated efforts to reduce operating costs.

Transportation and gas processing. These expenses all related to natural gas and NGL sales. These expenses on a per Mcfe basis were $0.34, $0.34 and $0.36 for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. The lower rates for the most recent periods were primarily attributable to improved negotiated rates for certain South Texas fields.

Depreciation, Depletion and Amortization ("DD&A"). These expenses on a per Mcfe basis were $0.84, $0.95 and $1.21 for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. The depletion expense recorded subsequent to April 22, 2016 is not comparable to predecessor period due to the restatement of assets at their fair value upon emergence from bankruptcy. The decreased per Mcfe amount for the year ended December 31, 2017 (successor) compared to the period of April 23, 2016 through December 31, 2016 (successor) is attributable to a lower depletion rate due to higher reserves, offset in part by a higher depletable base.

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.53, $0.59 and $0.55 for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. The decrease was primarily due to lower salaries and burdens, lower professional fees and lower office rent, partially offset by a higher corporate benefit accrual and lower capitalized amounts.

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.15, $0.18 and $0.23 for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively. Severance and other taxes, as a percentage of oil and gas sales, were approximately 4.2%, 5.5% and 9.1% for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (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 $15.9 million, $15.8 million and $13.3 million for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor), respectively, of which $0.8 million and $0.5 million was capitalized for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively. The decrease in gross interest from 2016 was primarily due to the discontinuance of interest on our DIP Credit Agreement as well as lower borrowing rates given the termination of the non-conforming borrowing base on our Credit Facility, partially offset by additional interest on our Second Lien Notes.

Income Taxes. The Company recognized a tax gain from the reversal of a valuation allowance for alternative minimum tax credit carryovers. As discussed further below, the Company has significant deferred tax assets in excess of deferred tax liabilities. Because of uncertainty about the realization of any future tax benefits, the Company had carried a full valuation allowance against its net deferred asset balance. On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the "Act"). The Act makes broad and complex changes to the U.S. tax code that includes a repeal of the alternative minimum tax regime. Under the transition rules related to the repeal of the alternative minimum tax regime, the alternative minimum tax credit carryforward of $2 million will be refundable in 2018-2021, if not used to offset regular tax liability. As a result, management determined that the valuation allowance for the alternative minimum tax credit carryforward was no longer necessary. The valuation allowance for the remaining deferred tax assets remain in place. Tax expense that would have been recognized at the statutory rate for 2017 was offset by a reduction in the valuation allowance carried forward from 2016.

2016 - Our costs and expenses during 2016 versus 2015 were as follows:

General and Administrative Expenses, Net. These expenses on a per Mcfe basis were $0.59, $0.55 and $0.64 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.

Depreciation, Depletion and Amortization ("DD&A"). These expenses on a per Mcfe basis were $0.95, $1.21 and $2.65 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 Mcfe 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.

Lease Operating Cost. These expenses on a per Mcfe basis were $0.67, $0.89 and $1.05 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 natural gas and NGL sales. These expenses on a per Mcfe basis were $0.34, $0.36 and $0.33 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.

Severance and Other Taxes. These expenses on a per Mcfe basis were $0.18, $0.23 and $0.26 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.

Non-GAAP Financial Measures

Adjusted EBITDA

We present adjusted EBITDA attributable to common stockholders ("Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP. Adjusted EBITDA is a non-GAAP financial measure that is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures. We define Adjusted EBITDA as net income (loss):

Plus/(Less):

- Depreciation, depletion, amortization;
- Accretion of asset retirement obligations;
- Interest expense;
- Impairment of oil and natural gas properties;
- Reorganization items;
- Net losses (gains) on commodity derivative contracts;
- Amounts collected (paid) for commodity derivative contracts held to settlement;
- Income tax expense or (benefit); and
- Share-based compensation expense.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of other companies because all companies may not calculate Adjusted EBITDA in the same manner.

The following tables present reconciliations of our net income (loss) (the most directly comparable financial measure calculated in accordance with U.S. GAAP) to Adjusted EBITDA for the periods indicated (in thousands):

	Successor		Predecessor
	Year Ended December 31, 2017	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**
Net Income (Loss)	$ 71,971	$ (156,288)	$ 851,611
Plus:			
Depreciation, depletion and amortization	46,933	36,436	20,439
Accretion of asset retirement obligations	2,322	2,878	1,610
Interest expense	15,070	15,310	13,347
Impairment of oil and gas properties	—	133,496	77,732
Reorganization items	—	1,639	(956,142)
Derivative (gain)/loss	(17,913)	19,676	—
Derivative cash settlements collected/(paid) (1)	(1,545)	(2,130)	—
Income tax expense/(benefit)	(1,954)	—	—
Share-based compensation expense	6,849	3,618	886
Adjusted EBITDA	$ 121,733	$ 54,635	$ 9,483

(1) This includes accruals for settled contracts covering commodity deliveries during the period where the actual cash settlements occur outside of the period.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated 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 Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, followed by the issuance of certain additional related accounting standards updates (collectively codified in "ASC 606"), 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.

The Company is adopting this guidance effective January 1, 2018. In preparation for adoption, we evaluated our sales contracts and accounting procedures for recording revenue. We did not identify any material differences between our existing revenue recognition practices vs. the new guidance with respect to either timing or presentation in our financial statements. The Company's stated policy for recognition of revenue when sales for our account are not in proportion to our ownership interest in production was to use the entitlement method. The entitlement method is not available under the new standard. However, there were no disproportionate sales arrangements in place for any of the reporting periods presented. The Company is using the modified retrospective transition method of adoption, but adoption will not require an adjustment to retained earnings. The Company will provide expanded disclosures beginning with the quarter ended March 31, 2018 to comply with the requirements of this new guidance.

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, 2017 the Company's total lease commitments were approximately $6.2 million. Of this total, $2.0 million related to our corporate office sub-lease which has a remaining term of 3.4 years. The remaining are generally for equipment and vehicle leases, most of which are expiring during 2018.The Company is in the process of evaluating other contracts that may contain lease components that need to be recognized under this standard. 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 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. The Company will apply this new guidance to the statement of cash flows that will be included in our first quarter 2018 10-Q.

In January 2017, the FASB issued ASU 2017-01, to assist entities in evaluating whether transactions should be accounted for as an acquisition or disposal of an asset or business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities are not a business. The guidance is effective for companies beginning January 1, 2018 with early adoption permitted. The Company will apply this guidance to any new acquisition or disposal transactions that in may enter into after January 1, 2018.

In May 2017, the FASB issued ASU 2017-09, which provides clarity on what changes to share-based payment awards are considered substantive and require modification accounting to be applied. The guidance is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. The Company does not expect ASU 2017-09 to have a significant impact on our financial statements or disclosures.

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 condensed consolidated statement of operations as reorganization items for the period of January 1, 2016 through April 22, 2016.

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").

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 (defined herein as "Credit Facility") was established. For more information refer to Note 4 of the accompanying consolidated financial statements in this Form 10-K.

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 4 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.

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 (the "Exchange Act"). 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,
- 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;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- other risks and uncertainties described in Item 1A. “Risk Factors,” in this annual report on Form 10-K for the year ended December 31, 2017.

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, 2017. 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 5 of the consolidated financial statements in this Form 10-K.

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. For the year ended December 31, 2017, Kinder Morgan and affiliates accounted for approximately 48% of our oil and gas receipts. There were no other purchasers who individually accounted for 10% or more of our oil and gas receipts. We expect to continue this relationship in the future. We believe that the risk of these unsecured receivables is mitigated by the size, reputation and nature of the businesses and the availability of other purchasers in the areas where we operate.

Interest Rate Risk. At December 31, 2017, we had $73.0 million drawn under our Credit Facility, which bears a floating rate of interest depending on the level of the borrowing base and the borrowing base loans outstanding and therefore is susceptible to interest rate fluctuations. These variable interest rate borrowings are impacted by changes in short-term interest rates. A hypothetical one-percentage point increase in interest rates on our borrowings outstanding under our credit facility as of December 31, 2017 would increase our annual interest expense by $0.7 million.

Management's Report on Internal Control Over Financial Reporting

Management of SilverBow Resources, Inc. 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, 2017. 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, 2017.

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 2017 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, 2017, based on their audit.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
SilverBow Resources, Inc.
Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited SilverBow Resources, Inc.'s (the "Company's") internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016 (successor), and the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2017 (successor) and the periods from April 23, 2016 through December 31, 2016 (successor) and from January 1, 2016 through April 22, 2016 (predecessor), and the related notes and our report dated March 1, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/ BDO USA, LLP

Houston, Texas
March 1, 2018

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
SilverBow Resources, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of SilverBow Resources, Inc. (the "Company") as of December 31, 2017 and 2016 (successor) and the related consolidated statements of operations, stockholders' equity, and cash flows for the year ended December 31, 2017 (successor) and the periods from April 23, 2016 through December 31, 2016 (successor) and from January 1, 2016 through April 22, 2016 (predecessor), and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016 (successor) and the results of its operations and its cash flows for year ended December 31, 2017 (successor) and the periods from April 23, 2016 through December 31, 2016 (successor) and from January 1, 2016 through April 22, 2016 (predecessor) in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and our report dated March 1, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas
March 1, 2018

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of SilverBow Resources, Inc.

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
SilverBow Resources, Inc. (in thousands, except share amounts)

	Successor	
	December 31, 2017	December 31, 2016
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 7,806	$ 303
Accounts receivable, net	27,263	17,490
Fair value of commodity derivatives	5,148	458
Other current assets	2,352	3,228
Total Current Assets	42,569	21,479
Property and Equipment:		
Property and Equipment, Full Cost Method, including $50,377 and $33,354 of unproved property costs not being amortized	712,166	517,074
Less – Accumulated depreciation, depletion, amortization and impairment	(216,769)	(169,879)
Property and Equipment, Net	495,397	347,195
Other Long-Term Assets	13,304	8,625
Total Assets	$ 551,270	$ 377,299
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 44,437	$ 40,434
Fair value of commodity derivatives	5,075	15,823
Accrued capital costs	10,883	11,954
Accrued interest	2,106	1,721
Undistributed oil and gas revenues	12,996	9,192
Total Current Liabilities	75,497	79,124
Long-term debt	265,325	198,000
Asset retirement obligations	8,678	22,291
Other long-term liabilities	8,312	1,829
Commitments and Contingencies (Note 6)	—	—
Stockholders' Equity:		
Preferred stock, $.01 par value, 10,000,000 shares authorized, none issued	—	—
Common stock, $.01 par value, 40,000,000 shares authorized, 11,621,385 and 10,076,059 shares issued and 11,570,621 and 10,053,574 shares outstanding	116	101
Additional paid-in capital	279,111	232,917
Treasury stock held, at cost, 50,764 and 22,485 shares	(1,452)	(675)
Retained earnings (Accumulated deficit)	(84,317)	(156,288)
Total Stockholders' Equity	193,458	76,055
Total Liabilities and Stockholders' Equity	$ 551,270	$ 377,299

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

SilverBow Resources, Inc. (in thousands, except per-share amounts)

	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Revenues:				
Oil and gas sales	$ 195,910	$ 121,386	$ 43,027	$ 246,270
Operating Expenses:				
General and administrative, net	30,000	22,538	9,245	42,611
Depreciation, depletion, and amortization	46,933	36,436	20,439	177,512
Accretion of asset retirement obligations	2,322	2,878	1,610	5,572
Lease operating expense	21,908	25,777	14,933	70,188
Transportation and gas processing	19,360	13,038	6,090	21,741
Severance and other taxes	8,205	6,713	3,917	17,090
Write-down of oil and gas properties	—	133,496	77,732	1,562,086
Total Operating Expenses	128,728	240,876	133,966	1,896,800
Operating Income (Loss)	67,182	(119,490)	(90,939)	(1,650,530)
Non-Operating Income (Expense)				
Net gain (loss) on commodity derivatives	17,913	(19,677)	—	186
Interest expense, net	(15,070)	(15,310)	(13,347)	(75,870)
Reorganization items	—	(1,639)	956,142	(6,565)
Other income (expense), net	(8)	(172)	(245)	(1,735)
Income (Loss) Before Income Taxes	70,017	(156,288)	851,611	(1,734,514)
Income Tax Benefit	(1,954)	—	—	(80,543)
Net Income (Loss)	$ 71,971	$ (156,288)	$ 851,611	$ (1,653,971)
Per Share Amounts:				
Basic: Net Income (Loss)	$ 6.28	$ (15.61)	$ 19.06	$ (37.20)
Diluted: Net Income (Loss)	$ 6.25	$ (15.61)	$ 18.64	$ (37.20)
Weighted Average Shares Outstanding - Basic	11,453	10,013	44,692	44,463
Weighted Average Shares Outstanding - Diluted	11,514	10,013	45,697	44,463

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity (Deficit)
SilverBow Resources, Inc. (in thousands, except share amounts)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Deficit)	Total
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
Purchase of treasury shares (28,279 shares)	—	—	(777)	—	(777)
Issuance of common stock (1,403,508 shares)	14	39,166	—	—	39,180
Issuance of restricted stock (141,818 shares)	1	(1)	—	—	—
Share-based compensation	—	7,029	—	—	7,029
Net Income	—	—	—	71,971	71,971
Balance, December 31, 2017 (Successor)	$ 116	$ 279,111	$ (1,452)	$ (84,317)	$ 193,458

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

SilverBow Resources, Inc. (in thousands)

	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Cash Flows from Operating Activities:				
Net income (loss)	$ 71,971	$ (156,288)	$ 851,611	$ (1,653,971)
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
Depreciation, depletion, and amortization	46,933	36,436	20,439	177,512
Accretion of asset retirement obligation	2,322	2,878	1,610	5,572
Deferred income tax benefit	—	—	—	(80,133)
Share-based compensation expense	6,849	3,618	886	4,435
Loss (gain) on derivatives	(17,913)	19,676	—	(186)
Cash settlements (paid) received on derivatives	(1,411)	(1,928)	—	2,544
Settlements of asset retirement obligations	(2,335)	(2,993)	(848)	—
Write-down of debt issuance cost	2,676	—	—	—
Reorganization items (non-cash)	—	—	(977,696)	6,565
Other	(559)	1,351	229	(3,189)
Change in operating assets and liabilities-				
(Increase) decrease in accounts receivable and other assets	(7,169)	16,812	(5,474)	26,747
Increase (decrease) in accounts payable and accrued liabilities	6,089	(6,689)	(9,647)	(15,003)
Increase (decrease) in income taxes payable	—	—	—	(435)
Increase (decrease) in accrued interest	385	1,058	(308)	9,730
Net Cash Provided by (Used in) Operating Activities	107,838	47,427	(41,466)	42,274
Cash Flows from Investing Activities:				
Additions to property and equipment	(192,982)	(45,671)	(24,530)	(139,688)
Acquisition of producing properties	(9,426)	—	—	—
Proceeds from the sale of property and equipment	702	45,985	48,661	1,164
Net Cash Provided by (Used in) Investing Activities	(201,706)	314	24,131	(138,524)
Cash Flows from Financing Activities:				
Proceeds from long-term debt issuances	198,000	—	—	—
Proceeds from bank borrowings	404,700	84,000	328,000	281,100
Payments of bank borrowings	(529,700)	(139,000)	(324,900)	(153,500)
Net proceeds from issuances of common stock	39,179	—	—	302
Purchase of treasury shares	(777)	(675)	(4)	(154)
Payments of debt issuance costs	(10,031)	(502)	(6,482)	(2,444)
Net Cash Provided by (Used in) Financing Activities	101,371	(56,177)	(3,386)	125,304
Net Increase (Decrease) in Cash and Cash Equivalents	7,503	(8,436)	(20,721)	29,054
Cash and Cash Equivalents at Beginning of				

Period	303	8,739	29,460	406
Cash and Cash Equivalents at End of Period	$ 7,806	$ 303	$ 8,739	$ 29,460
Supplemental Disclosures of Cash Flows Information:				
Cash paid during period for interest, net of amounts capitalized	$ 10,428	$ 12,517	$ 10,367	$ 63,132
Cash paid during period for income taxes	$ —	$ —	$ —	$ 450
Cash paid for reorganization items	$ —	$ 12,929	$ 15,643	$ —
Changes in capital accounts payable and capital accruals	$ 9,894	$ (6,265)	$ 1,843	$ (27,611)
Changes in other long-term liabilities for capital expenditures	$ 5,000	$ —	$ —	$ —

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
SilverBow Resources, Inc. and Subsidiaries

1. Summary of Significant Accounting Policies

Fresh Start Accounting. Upon emergence from bankruptcy on April 22, 2016, the Company adopted Fresh Start Accounting. As a result of the application of fresh start accounting, as well as the effects of the implementation of the joint plan of reorganization (the "Plan"), the Consolidated Financial Statements after April 22, 2016, 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 April 23, 2016. See Notes 12 and 13 for further details.

Basis of Presentation. The consolidated financial statements included herein 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 SilverBow 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. On January 24, 2018 the Company executed a definitive purchase and sale agreement to divest certain wells in its AWP Olmos field for $28.8 million. This transaction closed on March 1, 2018 and has an effective date of January 1, 2018. The buyer will assume approximately $6.2 million in asset retirement obligations. Additionally, on February 28, 2018 the Company signed a one-year contract for a second drilling rig.

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. Such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, 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 commodity derivative assets and liabilities,
- estimates in the assessment of current litigation claims against the Company,
- estimates in amounts due with respect to open state regulatory audits, and
- the estimates of reorganization value, enterprise value and fair value of assets and liabilities upon emergence from bankruptcy and application of fresh start accounting.

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

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 year ended December 31, 2017 (successor), 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), such internal costs capitalized totaled $4.6 million, $5.4 million, $2.9 million and $12.7 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 4 of these consolidated financial statements for further discussion on capitalized interest costs).

The following is a detailed breakout of our "Property and Equipment" balances (in thousands):

	Successor	
	December 31, 2017	**December 31, 2016**
Property and Equipment		
Proved oil and gas properties	$ 658,519	$ 480,499
Unproved oil and gas properties	50,377	33,354
Furniture, fixtures, and other equipment	3,270	3,221
Less – Accumulated depreciation, depletion, amortization and impairment	(216,769)	(169,879)
Property and Equipment, Net	$ 495,397	$ 347,195

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

We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties—including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and natural gas produced (which excludes natural gas consumed in operations) during the period by the total estimated units of proved oil and natural gas reserves (which excludes natural gas consumed in operations) at the beginning of the period. Future development costs are estimated on a property-by-property basis based on current economic conditions. 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, 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 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 quarterly 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.

There was no write-down for the year ended December 31, 2017 (successor). 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. 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, on our oil and natural gas properties.

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 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. The Company uses the entitlement method of accounting for gas imbalances in which we recognize our ownership interest in such 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, 2017 and 2016, we did not have any material natural gas imbalances.

Accounts Receivable, Net. 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, 2017 and 2016, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying consolidated balance sheets.

At December 31, 2017, our "Accounts receivable" balance included $20.1 million for oil and gas sales, $2.1 million for joint interest owners, $2.1 million for severance tax credit receivables and $3.0 million for other receivables. 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.

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 year ended December 31, 2017 (successor), 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) did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $4.7 million, $4.5 million, $2.7 million and $9.2 million for the year ended December 31, 2017 (successor), 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.

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 likelihood 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, 2017, 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 did not incur a cash income tax liability as a result of emergence from bankruptcy on April 22, 2016. The Company fully absorbed cancellation of debt income generated in the bankruptcy reorganization with its then existing NOL carryforwards. The amount of remaining NOL carryforward available following emergence from bankruptcy was limited under United States Internal Revenue Code 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, 2016 and December 31, 2017, leaving the Company in a net deferred tax asset position as of such dates. 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.

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, 2017	December 31, 2016
Trade accounts payable	$ 20,884	$ 12,372
Accrued operating expenses	3,490	2,990
Accrued compensation costs	5,334	4,730
Asset retirement obligations – current portion	2,109	9,965
Accrued non-income based taxes	3,898	3,937
Accrued corporate and legal fees	2,784	3,075
Other payables	5,938	3,365
Total Accounts payable and accrued liabilities	$ 44,437	$ 40,434

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents. These amounts do not include cash balances that are contractually restricted.

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 7 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 year ended December 31, 2017 (successor), 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) parties that accounted for approximately 10% or more of our total oil and gas receipts were as follows:

	Successor		Predecessor	
Sellers greater than 10%	**Year Ended December 31, 2017**	**Period from April 23, 2016 through December 31, 2016**	**Period from January 1, 2016 through April 22, 2016**	**Year Ended December 31, 2015**
Kinder Morgan	48%	38%	20%	27%
Plains Marketing [1]	—%	14%	14%	18%
Howard Energy [1]	—%	—%	11%	13%
Southcross Energy [1]	—%	—%	11%	—%
Shell [1]	—%	15%	19%	16%

(1) Less than 10% for the year ended December 31, 2017 (successor).

Treasury Stock. 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, 2017 (successor), 28,279 treasury shares were purchased to satisfy withholding tax obligations arising upon the vesting of restricted shares. For the period of April 23, 2016 through December 31, 2016 (successor), 22,485 treasury shares were purchased in connection with the retirements of the former Chief Executive Officer and the former Chief Financial Officer.

New Accounting Pronouncements. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, followed by the issuance of certain additional related accounting standards updates (collectively codified in “ASC 606”), 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.

The Company is adopting this guidance effective January 1, 2018. In preparation for adoption, we evaluated our sales contracts and accounting procedures for recording revenue. We did not identify any material differences between our existing revenue recognition practices vs. the new guidance with respect to either timing or presentation in our financial statements. The Company’s stated policy for recognition of revenue when sales for our account are not in proportion to our ownership interest in production was to use the entitlement method. The entitlement method is not available under the new standard. However, there were no disproportionate sales arrangements in place for any of the reporting periods presented. The Company is using the modified retrospective transition method of adoption, but adoption will not require an adjustment to retained earnings. The Company will provide expanded disclosures beginning with the quarter ended March 31, 2018 to comply with the requirements of this new guidance.

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, 2017 the Company’s total lease commitments were approximately $6.2 million. Of this total, $2.0 million related to our corporate office sub-lease which has a remaining term of 3.4 years. The remaining are generally for equipment and vehicle leases, most of which are expiring during 2018.The Company is in the process of evaluating other contracts that may contain lease components that need to be recognized under this standard. 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 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. The Company will apply this new guidance to the statement of cash flows that will be included in our first quarter 2018 10-Q.

In January 2017, the FASB issued ASU 2017-01, to assist entities in evaluating whether transactions should be accounted for as an acquisition or disposal of an asset or business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities are not a business. The guidance is effective for companies beginning January 1, 2018 with early adoption permitted. The Company will apply this guidance to any new acquisition or disposal transactions that in may enter into after January 1, 2018.

In May 2017, the FASB issued ASU 2017-09, which provides clarity on what changes to share-based payment awards are considered substantive and require modification accounting to be applied. The guidance is effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. The Company does not expect ASU 2017-09 to have a significant impact on our financial statements or disclosures.

2. Earnings Per Share

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 12, 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 be issuable, according to predetermined performance and market goals, as 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 year ended 2015 (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 year ended 2017 (successor), 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 2015 (predecessor) (in thousands, except per share amounts):

	Successor Year Ended December 31, 2017			Successor from April 23, 2016 through December 31, 2016		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ 71,971	11,453	$ 6.28	$ (156,288)	10,013	$ (15.61)
Dilutive Securities:						
Restricted Stock Awards		6			—	
Restricted Stock Units Awards		—			—	
Stock Option Awards		55			—	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$ 71,971	11,514	$ 6.25	$ (156,288)	10,013	$ (15.61)

	Predecessor from January 1, 2016 through April 22, 2016			Predecessor Year Ended December 31, 2015		
	Net Income (Loss)	Shares	Per Share Amount	Net Income (Loss)	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ 851,611	44,692	$ 19.06	$ (1,653,971)	44,463	$ (37.20)
Dilutive Securities:						
Restricted Stock Awards		1,005			—	
Restricted Stock Unit Awards		—			—	
Stock Option Awards		—			—	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$ 851,611	45,697	$ 18.64	$ (1,653,971)	44,463	$ (37.20)

Approximately 0.3 million and 0.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively, 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 stock options to purchase shares were not included in the computation of Diluted EPS for the year ended December 31, 2015 (predecessor) 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 year ended December 31, 2015 (predecessor) were not included in the computation of Diluted EPS because they were antidilutive.

Approximately 0.1 million and 0.2 million shares related to restricted stock units were not included in the computation of Diluted EPS for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively, 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 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 year ended December 31, 2015 (predecessor), 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 discussed in Note 12 of these consolidated financial statements). These warrants were not included in the computation of Diluted EPS for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), as they were antidilutive.

3. Provision (Benefit) for Income Taxes

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

	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Income (Loss) Before Income Taxes	$ 70,017	$ (156,288)	$ 851,611	$ (1,734,514)

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

	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Current	$ (1,954)	$ —	$ —	$ (410)
Deferred	—	—	—	(80,133)
Total	**$ (1,954)**	**$ —**	**$ —**	**$ (80,543)**

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	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Federal Statutory Rate	35.0 %	35.0 %	35.0 %	35.0 %
State tax provisions (benefits), net of federal benefits	1.6 %	0.9 %	0.9 %	1.0 %
Reorganization Adjustments	— %	— %	(1.8)%	— %
Expiration/Write-off of NOL Carryovers	13.9 %	(74.9)%	— %	— %
Change in Enacted Tax Rates	55.6 %	— %	— %	— %
Executive Compensation Limitation	0.6 %	— %	— %	— %
Other, net	2.3 %	0.2 %	1.0 %	(0.1)%
Valuation allowance adjustments	(111.8)%	38.9 %	(35.1)%	(31.3)%
Effective rate	(2.8)%	— %	— %	4.6 %

The tax effects of temporary differences representing the net deferred tax asset (liability) at December 31, 2017 and 2016 were as follows (in thousands):

	Successor	
	Year Ended December 31, 2017	Year Ended December 31, 2016
Deferred tax assets:		
Federal net operating loss (“NOL”) carryovers	$ 58,438	$ 40,104
Oil and gas exploration and development costs	—	71,292
Alternative minimum tax credits	138	2,092
Other Carryover Items	619	1,107
Asset Retirement Obligations	2,329	11,447
Derivative Contracts	29	5,802
Unrealized share-based compensation	872	648
Other	2,190	4,164
Valuation allowance	(58,398)	(136,656)
Total deferred tax assets	**$ 6,217**	**$ —**
Deferred tax liabilities:		
Oil and gas exploration and development costs	$ (6,054)	$ —
Other	(163)	—
Total deferred tax liabilities	**(6,217)**	**—**
Net deferred tax liabilities	**$ —**	**$ —**

The 2016 reorganization and emergence from bankruptcy had a significant impact on the Company’s tax attributes. The Company’s net operating loss carryforward (NOL) was $1.3 billion as of December 31, 2016. The Company was able to fully absorb cancellation of debt income (CODI) of $854 million from the reorganization with NOL carryforwards, reducing the available NOL carryforward to $451 million. The Company’s remaining NOL carryforward is severely limited under Sec. 382 due to the change in control annual limitation of $6 million. The NOL carryforward that will expire before utilization due to the IRC Sec. 382 limitation is estimated to be $337 million. A substantial portion of the deferred tax asset associated with the NOLs expected to expire was written off in 2016 and the remaining portion was written off in 2017. The remaining NOL carryforward after excess Sec. 382 limitation is $114 million. The current year taxable loss has increased the available NOL carryforward to $278 million as of December 31, 2017, which will expire in 2033 through 2037 if not utilized in earlier periods.

The Company was in a net deferred tax asset position at December 31, 2017 and 2016. 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 $58 million and $137 million at December 31, 2017 and 2016, respectively.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the "Act"). The Act makes broad and complex changes to the U.S. tax code that includes, among other provisions, a permanent reduction of the U.S. federal corporate tax rate from 35% to 21% and a repeal of the alternative minimum tax regime, both effective January 1, 2018. The remeasurement of the Company’s deferred tax balances to reflect the reduced corporate income tax rate as of December 31, 2017 resulted in a $39 million reduction in the net deferred tax asset balance with a corresponding reduction in the previously established valuation allowance. Under the transition rules related to the repeal of the alternative minimum tax regime, the alternative minimum tax credit carryforward of $2 million will be refundable in 2018 through 2021, if not used to offset regular tax liability. The previously established valuation allowance against the AMT credit carryforward has been released, resulting in a tax benefit of $2 million.

The provisions of the Act, including its extensive transition rules, are complex and interpretive guidance continues to develop. The final application of the Act to the Company’s financial results may differ from what we have provisionally provided for as of December 31, 2017. Changes could arise as regulatory and interpretive action continues to clarify aspects of the Act and as changes are made to estimates that the Company has utilized in calculating the transition impacts.

As of December 31, 2017, 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 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.

4. Long-Term Debt

As of December 31, 2017 and December 31, 2016, the Company's long-term debt consisted of the following (in thousands):

	December 31, 2017	December 31, 2016
Bank Borrowings [(1)]	$ 73,000	$ 198,000
Second Lien Notes due 2024	200,000	—
	273,000	198,000
Unamortized discount on Second Lien Notes due 2024	(1,992)	—
Unamortized debt issuance cost on Second Lien Notes due 2024	(5,683)	—
Total Long-Term Debt	$ 265,325	$ 198,000

(1) Unamortized debt issuance costs on our Credit Facility borrowing are included in "Other Long-Term Assets" in our consolidated balance sheet. As of December 31, 2017 we had $5.5 million in unamortized debt issuance costs.

Revolving Credit Facility. Amounts outstanding under our Credit Facility (defined below) were $73.0 million and $198.0 million as of December 31, 2017 and 2016, respectively. As discussed in Note 12 of these consolidated financial statements, on April 22, 2016 (the "Effective Date"), the Prior First Lien Credit Facility was terminated and paid in full, and the Company entered into a Senior Secured Revolving Credit Agreement among the Company as borrower, JPMorgan Chase Bank, National Association as administrative agent, and certain lenders party thereto. On April 19, 2017, the Company amended and restated the Senior Secured Revolving Credit Agreement by entering into a First Amended and Restated Senior Secured Revolving Credit Agreement (the "Credit Agreement") among the Company as borrower, JPMorgan Chase Bank, N.A. as administrative agent, and certain lenders that are a party thereto, which provides for revolving loans of up to the borrowing base then in effect (the "Credit Facility"). The Credit Facility matures April 19, 2022. The maximum credit amount under the Credit Facility is currently $600 million with a borrowing base of $330 million. The borrowing base is scheduled to be redetermined in May and November of each calendar year and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. Additionally, each of the Company and the administrative agent may request an unscheduled redetermination of the borrowing base between scheduled redeterminations. The amount of the borrowing base is determined by the lenders in their discretion and consistent with their oil and gas lending criteria at the time of the relevant redetermination. The Company may also request the issuance of letters of credit under the Credit Agreement in an aggregate amount up to $25 million, which reduce the amount of available borrowings under the borrowing base in the amount of such issued and outstanding letters of credit.

Interest under the Credit Facility accrues at the Company's option either at an Alternative Base Rate plus the applicable margin ("ABR Loans") or the LIBOR Rate plus the applicable margin ("Eurodollar Loans"). The applicable margin ranges from 1.75% to 2.75% for ABR Loans and 2.75% to 3.75% for Eurodollar Loans. The Alternate Base Rate and LIBOR Rates are defined, and the applicable margins are set forth, in the Credit Agreement. Undrawn amounts under the Credit Facility are subject to a 0.50% commitment fee. To the extent that a payment default exists and is continuing, all amounts outstanding under the Credit Facility will bear interest at 2.00% per annum above the rate and margin otherwise applicable thereto.

The obligations under the Credit Agreement 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 85% of estimated proved reserves of the Company and its subsidiaries.

The Credit Agreement contains the following financial covenants:

- a ratio of total debt to EBITDA, as defined in the Credit Agreement, for the most recently completed four fiscal quarters, not to exceed 4.0 to 1.0 as of the last day of each fiscal quarter; and

- a current ratio, as defined in the Credit Agreement and which includes in the numerator available borrowings undrawn under the borrowing base, of not less than 1.0 to 1.0 as of the last day of each fiscal quarter.

As of December 31, 2017, the Company was in compliance with all financial covenants under the Credit Agreement.

Additionally, the Credit Agreement contains certain representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Credit Agreement contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Credit Facility to be immediately due and payable.

Interest expense on the Credit Facility, which includes commitment fees and amortization of debt issuance costs, totaled $14.9 million and $15.3 million for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively. Additionally, interest expense for the year ended December 31, 2017 (successor) includes a write-down of debt issuance costs of $2.7 million. The amount of commitment fee amortization included in interest expense, net was $0.4 million and $0.2 million for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively.

We capitalized interest on our unproved properties in the amount $0.8 million and $0.5 million for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively.

Senior Secured Second Lien Notes. On December 15, 2017, the Company entered into a note purchase agreement for Senior Secured Second Lien Notes (the "Second Lien") among the Company as issuer, U.S. Bank National Association as agent and collateral agent (the "Second Lien Agent"), and certain holders that are a party thereto, and issued notes in an initial principal amount of $200 million, with a $2.0 million discount, for net proceeds of $198.0 million (the "Second Lien Facility"). The Company has the ability, subject to the satisfaction of certain conditions (including compliance with the Asset Coverage Ratio described below and the agreement of the holders to purchase such additional notes), to issue additional notes in a principal amount not to exceed $100 million. The Second Lien matures on December 15, 2024.

Interest under the Second Lien is payable quarterly and accrues at LIBOR plus 7.5%; provided that if LIBOR ceases to be available, the Second Lien provides for a mechanism to use ABR (an alternate base rate) plus 6.5% as the applicable interest rate. The definitions of LIBOR and ABR are set forth in the Second Lien. To the extent that a payment, insolvency or, at the holders' election, another default exists and is continuing, all amounts outstanding under the Second Lien will bear interest at 2.0% per annum above the rate and margin otherwise applicable thereto. Additionally, to the extent the Company were to default on the Second Lien, this would potentially trigger a cross-default on our Credit Facility.

The Company has the right, to the extent permitted under the Credit Facility and subject to the terms and conditions of the Second Lien, to optionally prepay the notes issued pursuant to the Second Lien, subject to the following repayment fees: during years one and two, a customary "make-whole" amount (which is equal to the present value of the remaining interest payments through the twenty-four month anniversary of the issuance of the Second Lien, discounted at a rate equal to the Treasury Rate plus 50 basis points) plus 2.0% of the principal amount of the notes repaid; during year three, 2.0% of the principal amount of the notes being prepaid; during year four, 1.0% of the principal amount of the notes being prepaid; and thereafter, no premium. Additionally, the Second Lien contains customary mandatory prepayment obligations upon asset sales (including hedge terminations), casualty events and incurrences of certain debt, subject to, in certain circumstances, reinvestment periods. Management has deemed the probability of mandatory prepayment due to default is remote.

The obligations under the Second Lien are secured, subject to certain exceptions and other permitted liens (including the liens created under the Credit Facility), by a perfected security interest, second in priority to the liens securing our Credit Facility, and mortgage lien on substantially all assets of the Company and certain of its subsidiaries, including a mortgage lien on oil and gas properties attributed with at least 85% of estimated PV-9 of proved reserves of the Company and its subsidiaries and 85% of the book value attributed to the PV-9 of the non-proved oil and gas properties of the Company. PV-9 is determined using commodity price assumptions by the Administrative Agent of the Credit Facility.

The Second Lien contains an Asset Coverage Ratio, which is only tested (i) as a condition to issue additional notes and (ii) in connection with certain asset sales in order to determine whether the proceeds of such asset sale must be applied as a prepayment of the notes and includes in the numerator the PV-10 (defined below), based on forward strip pricing, plus the swap mark-to-market value of the commodity derivative contracts of the Company and its restricted subsidiaries and in the denominator the total net indebtedness of the Company and its restricted subsidiaries, of not less than 1.25 to 1.0 as of each date of determination (the "Asset Coverage Ratio Requirement"). PV-10 value is 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%.

The Second Lien also contains a financial covenant measuring the ratio of total net debt to EBITDA, as defined in the purchase agreement, for the most recently completed four fiscal quarters, not to exceed 4.5 to 1.0 as of the last day of each fiscal quarter.

The Second Lien contains certain customary representations, warranties and covenants, including but not limited to, limitations on incurring debt and liens, limitations on making certain restricted payments, limitations on investments, limitations on asset sales and hedge unwinds, limitations on transactions with affiliates and limitations on modifying organizational documents and material contracts. The Second Lien contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Second Lien Facility to be immediately due and payable.

As of December 31, 2017, net amounts recorded for the Second Lien Notes $192.3 million, net of unamortized debt discount and debt issuance costs. Interest expense on the Second Lien totaled $0.8 million from the date of issuance through December 31, 2017 (successor).

Debt Issuance Costs. The Company capitalizes legal fees, accounting fees, underwriting fees, printing costs, and other direct expenses associated with issuing debt. The costs associated with our Second Lien Notes are amortized on an effective interest basis over the term of the Second Lien Notes, while issuance costs related to our line of credit arrangement are capitalized and amortized ratably over the term of the line of credit arrangement, regardless of whether there are any outstanding borrowings.

Bankruptcy Filing. As discussed in Note 12 of these consolidated condensed financial statements, 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 Company's previous credit facility (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 debtor-in-possession credit facility ("DIP Credit Agreement") (along with certain unsecured claims as discussed further in Note 12) were exchanged for 88.5% of the common stock of the reorganized entity. Additional information regarding the bankruptcy proceedings is included in Note 12 of these consolidated financial statements.

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. 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. 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 and $9.4 million for the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (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 for the year ended December 31, 2015 (predecessor), respectively.

Additionally, we capitalized interest on our unproved properties in the amount of $4.9 million for the year ended December 31, 2015 (predecessor). 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.

Prior Senior Notes Due. 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. There was no interest expense on the senior notes for the period of January 1, 2016 through April 22, 2016 (predecessor) due to our 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 for the year ended December 31, 2015 (predecessor).

5. 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 "Net gain (loss) on commodity derivatives" on the accompanying consolidated statements of operations. We have a price-risk management policy to use derivative instruments to protect against declines in oil, natural gas and NGL prices, mainly through the purchase of price swaps, collars and basis swaps.

For the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor) we recognized a $17.9 million gain and a $19.7 million loss, respectively, relating to our derivative activities. For the year ended December 31, 2015 (predecessor) we recognized a $0.2 million gain. The Company made net cash payments of $1.4 million and $1.9 million for settled derivative contracts for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor). For the year ended December 31, 2015 (predecessor) we received net cash payments of $2.5 million for settled derivative contracts. There were no derivative instruments outstanding during the period of January 1, 2016 through April 22, 2016 (predecessor).

As of December 31, 2017 and 2016 we had $2.2 million and $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 2018 and 2017, respectively. As of December 31, 2017 and 2016 we had $0.4 million and $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 2018 and 2017, respectively.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. As of December 31, 2017 and 2016 there was $5.1 million and $0.5 million in current unsettled derivative assets, while long-term unsettled derivative assets were $2.6 million and not material as of December 31, 2017 and 2016, which are included in other long-term assets. As of December 31, 2017 and 2016 there was $5.1 million and $15.8 million in current unsettled derivative liabilities and $2.8 million and $1.0 million in long-term unsettled derivative liabilities, which are included in other long-term liabilities.

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for all derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company 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 $0.1 million and $16.4 million net fair value liability at December 31, 2017 and December 31, 2016, respectively. For further discussion related to the fair value of the Company's derivatives, refer to Note 10 of these consolidated financial statements.

The following tables summarizes the weighted average prices as well as future production volumes for our unsettled derivative contracts in place as of December 31, 2017.

Oil Derivative Swaps (NYMEX WTI Settlements)	**Total Volumes (Bbls)**	**Weighted Average Price**	
2018 Contracts			
1Q18	151,000	$	52.80
2Q18	140,400	$	52.57
3Q18	130,400	$	52.40
4Q18	122,800	$	52.23
2019 Contracts			
1Q19	97,200	$	52.40
2Q19	92,700	$	52.32
3Q19	88,500	$	52.39
4Q19	84,500	$	52.30
2020 Contracts			
1Q20	51,000	$	51.49
2Q20	49,250	$	51.46
3Q20	47,500	$	51.42
4Q20	46,500	$	51.40

Natural Gas Derivative Swaps (NYMEX Henry Hub Settlements)	**Total Volumes (MMBtu)**	**Weighted Average Price**	
2018 Contracts			
1Q18	5,238,000	$	3.42
2Q18	8,245,000	$	2.86
3Q18	8,014,000	$	2.88
4Q18	7,976,000	$	2.96
2019 Contracts			
1Q19	6,016,000	$	3.07
2Q19	6,060,000	$	2.83
3Q19	5,550,000	$	2.84
4Q19	5,966,000	$	2.84
2020 Contracts			
1Q20	5,370,000	$	2.83
2Q20	1,170,000	$	2.86
3Q20	1,170,000	$	2.86
4Q20	1,170,000	$	2.86

NGL Derivative Swaps (OPIS Settlements)	**Total Volumes (Bbls)**	**Weighted Average Price**	
2018 Contracts			
1Q18	126,000	$	24.78
2Q18	118,200	$	24.78
3Q18	112,200	$	24.78
4Q18	148,200	$	24.78

Natural Gas Basis Derivative Swaps (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Weighted Average Price
2018 Contracts		
1Q18	5,105,000	$ (0.11)
2Q18	6,795,000	$ (0.04)
3Q18	3,020,000	$ (0.03)
4Q18	2,730,000	$ (0.09)
2019 Contracts		
1Q19	750,000	$ (0.11)

Oil Basis Derivative Swaps (NYMEX WTI and Argus Settlements)	Total Volumes (Bbls)	Weighted Average Price
2018 Contracts		
1Q18	20,000	$ 4.06
2Q18	30,000	$ 4.06
3Q18	30,000	$ 4.06
4Q18	30,000	$ 4.06

6. Commitments and Contingencies

Rental and lease expense was $4.2 million, $5.7 million, $4.5 million and $16.8 million for the year ended December 31, 2017 (successor), 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 rental and lease expense primarily relates 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. Additionally, on August 31, 2017 we amended the sub-lease agreement for additional office space. As of December 31, 2017, the minimum contractual obligations were approximately $2.0 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 $4.6 million for 2018, $0.7 million for 2019, $0.6 million for 2020, $0.3 million for 2021 and approximately $6.2 million in the aggregate.

We have gas transportation and processing minimum obligations amounting to $6.8 million for 2018, $8.4 million for 2019, $7.5 million for 2020, $0.3 million for 2021 and $23.0 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.

7. Share-Based Compensation

Share-Based Compensation Plans

Upon the Company's emergence from bankruptcy on April 22, 2016, as discussed in Note 12, the Company's previous share-based compensation plans were canceled and the new 2016 Equity Incentive Plan was approved in accordance with the joint plan of reorganization. Additionally, upon the emergence the awards issued under the previous share-based compensation plan 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 operating cash flows.

For the year ended December 31, 2017 (successor) and 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 3 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 year ended December 31, 2015 (predecessor), we recognized an income tax shortfall in earnings as referenced in Note 3 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 $6.8 million and $3.6 million for the year ended December 31, 2017 (successor) and the period of April 23, 2016 through December 31, 2016 (successor), respectively, and $0.9 million and $4.4 million for the period of January 1, 2016 through April 22, 2016 (predecessor) and the year ended December 31, 2015 (predecessor), respectively.

We capitalized in property and equipment $0.2 million of share-based compensation for the year ended December 31, 2017 (successor) and did not capitalize 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 year ended December 31, 2015 (predecessor) we capitalized $0.2 million and $1.4 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.

There was no share-based compensation recorded in lease operating cost for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the period of January 1, 2016 through April 22, 2016 (predecessor). Share-based compensation recorded in lease operating cost was $0.2 million for the year ended December 31, 2015 (predecessor).

Our shares available for future grant under our Share-Based Compensation plans were 549,665 at December 31, 2017. Each restricted stock award and restricted stock unit granted reduces the shares available for future grant by one share.

Stock Option Awards

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 five 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 year ended December 31, 2017:

	Stock Option Valuation Assumptions
Expected Dividend	—
Expected volatility	70.3%
Risk-free interest rate	1.99%
Expected life of stock option awards (in years)	5.7
Grant-date market value	$ 27.71
Grant-date fair value	$ 17.09

To estimate expected volatility of our 2017 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 6 year look-back period to estimate expected volatility of our stock option awards.

At December 31, 2017, we had $5.2 million in unrecognized compensation cost related to stock option awards. The following table represents stock option award activity for the year ended December 31, 2017:

	Shares		Wtd. Avg. Exer. Price
Options outstanding, beginning of period (successor)	105,811	$	23.25
Options granted	428,974	$	27.71
Options forfeited	(26,055)	$	26.96
Options canceled	—	$	—
Options exercised	—	$	—
Options outstanding, end of period (successor)	508,730	$	26.82
Options exercisable, end of period (successor)	112,338	$	25.47

Our outstanding stock option awards at December 31, 2017 had $1.7 million in aggregate intrinsic value. At December 31, 2017 the weighted average remaining contract life of stock option awards outstanding was 6.9 years and exercisable was 2.0 years. The total intrinsic value of stock option awards exercisable as of December 31, 2017 was $0.6 million.

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 five years).

As of December 31, 2017, we had unrecognized compensation expense of $7.1 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.8 years.

The following table represents restricted stock unit activity for the year ended December 31, 2017:

	Shares		Wtd. Avg. Grant Price
Restricted units outstanding, beginning of period (successor)	178,847	$	23.25
Restricted stock units granted	326,532	$	28.21
Restricted stock units forfeited	(16,821)	$	26.41
Restricted stock units vested	(141,818)	$	25.15
Restricted stock units outstanding, end of period (successor)	346,740	$	26.99

In accordance with their employment agreements, the former 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. The Company contributed on behalf of eligible employees an amount up to 100% of the first 6% of compensation based on the contributions made by the eligible employees in 2017 and 2% in 2016. The Company's 2017 and 2016 plan contributions of $0.5 million and $0.3 million were paid in cash during the first quarter of 2018 and 2017, respectively. The Company's contributions to the 401(k) savings plan were $0.7 million for the year ended December 31, 2015 (predecessor). These amounts were recorded as “General and administrative, net” on the accompanying consolidated statements of operations.

Predecessor Share-Based Compensation Awards

We previously had shares outstanding under multiple share-based compensation plans. 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 previous plans, stock option awards and other equity-based awards could be granted to employees, directors, and consultants, with directors only eligible to receive restricted awards. 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. As of December 31, 2015, this plan was terminated.

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

For the year ended December 31, 2015, the Company issued 609,238 shares of restricted stock to employees, consultants, and directors. The weighted average fair values of these shares when issued for the year ended December 31, 2015 was $2.64 per share. The grant date fair values of shares vested for the year ended December 31, 2015 was $6.1 million. 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 year ended December 31, 2015, the Company granted 216,450 performance-based restricted stock units. 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 year ended December 31, 2015. The weighted average grant date fair value for the restricted stock units granted during the year ended December 31, 2015 was $1.98 per unit. All of the remaining grants were canceled upon emergence from bankruptcy.

8. 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 for the year ended 2015 (predecessor). 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.

9. 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 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.

Effective July 31, 2017, we disposed of our Wheeler Ranch wells in AWP Olmos in South Texas. We received net proceeds of $0.7 million and the buyer's assumption of approximately $0.6 million of plugging and abandonment liability. No gain or loss was recorded on the sale of this property.

On November 6, 2017 the Company purchased the non-operating working interest of two joint interest partners in certain wells and leases in AWP Field. The value of these assets are concentrated in proved oil and gas reserves. This purchase constitutes a business combination. The acquisition cost of this interest was $9.4 million. Additionally, the Company assumed asset retirement obligations of $0.2 million. We determined that these amounts are representative of the fair value of these assets. The fair-value measurements of these assets and associated asset retirement obligations are based on inputs that are not observable in the market and thus represent Level 3 inputs. This fair value assessment is primarily based on the income stream forecast for these properties.

Effective December 22, 2017, the Company closed a Purchase and Sale contract to sell the Company's wellbores and facilities in Bay De Chene. The contract price of $16.3 million will be paid by the Company, as seller. The payments will be funded over time, passed through an escrow account, with funds being released as abandonment work is performed and certified to meet state requirements. The buyer assumed approximately $20.9 million of plugging and abandonment liability with no gain or loss recorded on the sale of this property. Of the $16.3 million to be paid by the Company, approximately $6 million was released in the first quarter of 2018 for completion of initial post-closing requirements. The remaining $10 million will be funded as the abandonment work is completed and certified. Based on the estimated timing of the abandonment work to be performed, $11.3 million has been included in accrued capital expenditures as a current liability and $5.0 million has been included in other long-term liabilities in the accompanying consolidated balance sheet as of December 31, 2017.

In accordance with the full cost method of accounting, no gains or losses were recognized on these disposition transactions as they were not considered a significant amount of reserves or the proceeds did not significantly alter the relationships between capitalized costs and reserves. The sales proceeds, accrued payments and removal of related asset retirement obligations were treated as adjustments to our proved oil and gas property accounts.

10. Fair Value Measurements

Fair Value on a Recurring Basis. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities approximate fair value due to the highly liquid or short-term nature of these instruments.

The carrying value of our revolving Credit Facility approximates fair value because the Company's current borrowing base rate does not materially differ from market rates for similar bank borrowings. The carrying value of our Second Lien Notes included in long-term debt approximates fair value because market conditions have not changed significantly since the Second Lien Notes were issued on December 15, 2017. These are considered Level 3 valuations (defined below).

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers.

The fair value 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.

The following table presents our assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2017 and 2016. For additional discussion related to the fair value of the Company's derivatives, refer to Note 5 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, 2017				
Assets				
Natural Gas Derivatives	$ 7.2	$ —	$ 7.2	$ —
Natural Gas Basis Derivatives	$ 0.3	$ —	$ 0.3	$ —
NGL Derivatives	$ 0.1	$ —	$ 0.1	$ —
Liabilities				
Natural Gas Derivatives	$ 1.3	$ —	$ 1.3	$ —
Natural Gas Basis Derivatives	$ 0.3	$ —	$ 0.3	$ —
Oil Derivatives	$ 5.2	$ —	$ 5.2	$ —
Oil Basis Derivatives	$ 0.1	$ —	$ 0.1	$ —
NGL Derivatives	$ 0.9	$ —	$ 0.9	$ —
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.

11. 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 12, 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, 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**
Accretion expense		2,322
Liabilities incurred for new wells and facilities construction		253
Reductions due to sold wells and facilities		(21,466)
Reductions due to plugged wells and facilities		(2,366)
Revisions in estimates		(212)
Asset Retirement Obligations as of December 31, 2017 (Successor)	**$**	**10,787**

At December 31, 2017 and 2016, approximately $2.1 million and $10.0 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. The 2017 and 2016 reductions due to sold wells and facilities are primarily attributable to the disposition of our assets in the Bay De Chene and Lake Washington fields, respectively.

12. 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 13 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 (defined herein as "Credit Facility") with an initial $320 million borrowing base was established. For more information refer to Note 4 of these consolidated financial statements.

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 4 of these consolidated financial statements.

13. 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 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.

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 1. 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 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 10 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 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 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 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	Year Ended 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

Supplementary Information (unaudited)

SilverBow Resources, Inc. 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, 2017	
Proved oil and gas properties	$ 658,519
Unproved oil and gas properties	50,377
	708,896
Accumulated depreciation, depletion, amortization and impairment	(215,480)
Net capitalized costs	$ 493,416
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

There were $50.4 million and $33.4 million of unproved property costs at December 31, 2017 and 2016, respectively, excluded from the amortizable base. 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, 2017 and 2016.

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

	Successor		Predecessor	
	Year Ended December 31, 2017	Period from April 23, 2016 through December 31, 2016	Period from January 1, 2016 through April 22, 2016	Year Ended December 31, 2015
Lease acquisitions and prospect costs	$ 44,569	$ 6,466	$ 2,695	$ 28,571
Exploration	—	—	—	—
Development [(1) (3)]	149,293	40,908	24,082	74,948
Acquisition of property	9,426	—	—	—
Total acquisition, exploration, and development [(2)]	$ 203,288	$ 47,374	$ 26,777	$ 103,519

(1) Facility construction costs and capital costs have been included in development costs, and totaled $11.6 million, $6.0 million, $2.2 million and $5.5 million for the year ended December 31, 2017 (successor), 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.

(2) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $4.6 million, $5.4 million, $2.9 million and $12.7 million for the year ended December 31, 2017 (successor), 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, respectively. In addition, the total includes $0.8 million, $0.5 million and $4.9 million for the year ended December 31, 2017 (successor), the period of April 23, 2016 through December 31, 2016 (successor) and the year ended December 31, 2015 (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 $2.3 million, $8.0 million, $0.4 million and ($10.3 million) for the year ended December 31, 2017 (successor), 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. Does not include accrued payments associated with our Bay De Chene sale for the year ended December 31, 2017 (successor).

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 the years ended December 31, 2017 and 2016 and Gruy audited 99% of our proved reserves as of December 31, 2015. Proved reserves, as of December 31, 2017, 2016 and 2015, 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 2017 average adjusted prices after differentials used in our calculations were $2.95 per Mcf of natural gas, $50.38 per barrel of oil, and $20.32 per barrel of NGL compared to $2.43 per Mcf of natural gas, $41.07 per barrel of oil, and $16.13 per barrel of NGL for the 12-month average 2016 prices and $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.

Estimates of Proved Reserves	**Total**	**Natural Gas**	**Oil**	**NGL**
	(Mcfe)	(Mcf)	(Bbls)	(Bbls)
Proved reserves as of December 31, 2015	421,638,060	311,688,398	10,108,833	8,216,111
Extensions, discoveries, and other additions [3]	92,804,898	92,804,900	—	—
Revisions of previous estimates [1]	326,679,690	270,749,891	1,821,443	7,500,190
Sales of minerals in place [4]	(42,349,578)	(7,915,022)	(4,844,064)	(895,030)
Production	(55,031,868)	(40,539,807)	(1,308,521)	(1,106,822)
Proved reserves as of December 31, 2016	743,741,202	626,788,360	5,777,691	13,714,449
Extensions, discoveries, and other additions [3]	317,023,521	250,063,107	2,054,571	9,105,498
Revisions of previous estimates [1]	(8,747,628)	(8,711,753)	29,178	(34,045)
Purchases of minerals in place	33,405,229	23,499,391	51,275	1,599,698
Sales of minerals in place [4]	(4,866,078)	(3,158,892)	(68,350)	(216,181)
Production	(56,134,862)	(45,745,137)	(684,670)	(1,048,063)
Proved reserves as of December 31, 2017	1,024,421,384	842,735,076	7,159,695	23,121,356
Proved developed reserves [2]:				
December 31, 2015	338,005,854	238,355,707	10,108,833	6,499,524
December 31, 2016	378,233,832	312,125,091	4,512,842	6,505,282
December 31, 2017	458,252,677	377,504,768	5,026,398	8,431,587
Proved undeveloped reserves				
December 31, 2015	83,632,206	73,332,691	—	1,716,587
December 31, 2016	365,507,610	314,663,510	1,264,849	7,209,167
December 31, 2017	566,168,707	465,230,305	2,133,297	14,689,769

(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 downward revisions for 2017 were primarily attributable to well performance of Bracken lease wells in our AWP field.

(2) At December 31, 2017, 2016 and 2015, 45%, 51% and 80% of our reserves were proved developed, respectively.

(3) We have added proved reserves through our drilling activities. 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 2016 extensions were all in the Fasken Eagle Ford area. The 2017 additions were primarily due to additions from drilling results and leasing of adjacent acreage.

(4) Includes the disposition of a portion of our AWP Olmos wells in South Texas in 2017 and Lake Washington, Masters Creek, Burr Ferry, South Bearhead Creek and Sun TSH fields in 2016. See Note 9 of the consolidated financial statements for more information.

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,		
	2017	2016	2015
Future gross revenues	$ 3,319,101	$ 1,980,642	$ 1,434,931
Future production costs	(1,027,860)	(750,823)	(688,427)
Future development costs [1]	(529,088)	(365,064)	(280,252)
Future net cash flows before income taxes	1,762,153	864,755	466,252
Future income taxes	(237,396)	(88,775)	(297)
Future net cash flows after income taxes	1,524,757	775,980	465,955
Discount at 10% per annum	(793,230)	(368,987)	(92,190)
Standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves	$ 731,527	$ 406,993	$ 373,765

(1) These amounts include future costs related to asset retirement obligations for proved undeveloped oil and natural gas reserves.

The standardized measure of discounted future net cash flows from production of proved reserves as of December 31, 2017, 2016 and 2015, 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, 2017, 2016 and 2015:

	2017	2016	2015
Beginning balance	$ 406,993	$ 373,765	$ 1,651,674
Revisions to reserves proved in prior years:			
Net changes in prices, net of production costs	204,445	(46,553)	(2,018,065)
Net changes in future development costs	35,735	(152,600)	817,324
Net changes due to revisions in quantity estimates	(8,926)	264,124	(599,342)
Accretion of discount	44,193	33,327	194,326
Other	27,056	28,888	119,483
Total revisions	302,503	127,186	(1,486,274)
New field discoveries and extensions, net of future production and development costs	121,117	75,034	3,025
Purchase of reserves	11,491	—	—
Sales of minerals in place	(1,953)	(76,327)	—
Sales of oil and gas produced, net of production costs	(146,471)	(93,945)	(137,251)
Previously estimated development costs incurred	75,968	36,218	51,149
Net change in income taxes	(38,121)	(34,938)	291,442
Net change in standardized measure of discounted future net cash flows	324,534	33,228	(1,277,909)
Ending balance	$ 731,527	$ 406,993	$ 373,765

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the year ended December 31, 2017 (successor), the period of January 1, 2016 through April 22, 2016 (predecessor) and the period of April 23, 2016 through December 31, 2016 (successor) (in thousands, except per share data):

	Oil and Gas Sales	Net Income (Loss) Before Taxes	Net Income (Loss)	Basic EPS	Diluted EPS
2017 (Successor)					
First	$ 42,412	$ 17,710	$ 17,710	$ 1.58	$ 1.57
Second	45,785	16,241	16,241	1.41	1.41
Third	49,019	12,884	12,884	1.12	1.12
Fourth	58,694	23,182	25,136	2.17	2.17
Total	$ 195,910	$ 70,017	$ 71,971	$ 6.28	$ 6.25
January 1 - April 22, 2016 (Predecessor)					
First (1)	$ 34,367	$ (108,303)	$ (108,303)	$ (2.42)	$ (2.42)
April 1 - April 22, 2016	8,660	959,914	959,914	21.45	21.03
Total	$ 43,027	$ 851,611	$ 851,611	$ 19.06	$ 18.64
April 23 - December 31, 2016 (Successor)					
April 23 - June 30, 2016 (1)	$ 30,581	$ (149,601)	$ (149,601)	$ (14.96)	$ (14.96)
Third	47,959	394	394	0.04	0.04
Fourth	42,846	(7,081)	(7,081)	(0.71)	(0.71)
Total	$ 121,386	$ (156,288)	$ (156,288)	$ (15.61)	$ (15.61)

(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) we reported non-cash impairment write-downs on a before-tax basis of $77.7 million.

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.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the fourth quarter of 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. See management's report on internal control over financial reporting at Item 8 in this Form 10-K.

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 15, 2018 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 15, 2018 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 15, 2018 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 15, 2018 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 15, 2018 annual shareholders' meeting is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

1. The following consolidated financial statements of SilverBow Resources, Inc. together with the reports thereon of Ernst & Young LLP dated March 4, 2016 and BDO USA, LLP dated March 1, 2018, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

None.

3. Exhibits

3.1	First Amended and Restated Certificate of Incorporation of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.1 to SilverBow Resources, Inc,'s Form 10-Q filed May 8, 2017, File No. 001-087541).
3.2	First Amended and Restated Bylaws of SilverBow Resources, Inc., effective May 5, 2017 (incorporated by reference as Exhibit 3.2 to SilverBow Resources, Inc.'s Form 10-Q filed May 8, 2017, File No. 001-08754).
4.1	Form of stock certificate for common stock, $0.01 par value per share (incorporated by reference as Exhibit 4.6 to SilverBow Resources Inc,'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 SilverBow Resources, Inc. and the stockholders party thereto (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed April 28, 2016, File No. 001-08754).
4.3	Registration Rights Agreement, dated as of January 26, 2017, by and among SilverBow Resources, Inc. and the Purchasers named therein (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed February 1, 2017, File No 001-08754).
4.4	Director Nomination Agreement, dated as of April 22, 2016, by and among SilverBow Resources, Inc. and the stockholders party thereto (incorporated by reference as Exhibit 4.7 to SilverBow Resources, Inc.'s Form S-8 filed April 27, 2016, File No. 333-210936).
10.1	First Amended and Restated Senior Secured Revolving Credit Agreement among SilverBow Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders that are a party thereto (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed April 21, 2017, File No. 001-08754).
10.2*	First Amendment to First Amended and Restated Senior Secured Revolving Credit Agreement among SilverBow Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as administrative agent and certain lenders that are a party thereto.
10.3	Second Amendment to First Amended and Restated Senior Secured Revolving Credit Agreement dated as of December 15, 2017 by and among SilverBow Resources, Inc., as borrower, JPMorgan Chase Bank, N.A., as administrative agent, the guarantors party thereto and certain lenders party thereto (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed December 19, 2017).

10.4	Note Purchase Agreement dated as of December 15, 2017 by and among SilverBow Resources, Inc., as issuer, U.S. Bank National Association, as agent and collateral agent and the purchasers party thereto (incorporated by reference as Exhibit 10.2 to SilverBow Resources, Inc.'s Form 8-K filed December 19, 2017).
10.5	Intercreditor Agreement dated as of December 15, 2017 by and among SilverBow Resources, Inc., as borrower, certain of its subsidiaries, as grantors, JPMorgan Chase Bank, N.A., as first lien administrative agent and U.S. Bank National Association, as second lien collateral agent (incorporated by reference as Exhibit 10.3 to SilverBow Resources, Inc.'s Form 8-K filed December 19, 2017).
10.6	Warrant Agreement, dated as of April 22, 2016, between SilverBow Resources, Inc. and American Stock Transfer & Trust Company, LLC (incorporated by reference as Exhibit 10.4 to SilverBow Resources Inc.'s Form 8-K filed April 28, 2016, File No. 001-08754).
10.7	Share Purchase Agreement, dated as of January 20, 2017, by and among SilverBow Resources, Inc. and the Purchasers named therein (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed January 25, 2017, File No. 001-08754).
10.8+	SilverBow Resources, Inc. 2016 Equity Incentive Plan (incorporated by reference as Exhibit 4.1 to SilverBow Resources Inc.'s Form S-8 filed April 27, 2016, File No. 333- 210936).
10.9+	Amendment to SilverBow Resources, Inc. 2016 Equity Incentive Plan, effective May 5, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed May 5, 2017, File No. 001-08754).
10.10+	First Amendment to SilverBow Resources, Inc. 2016 Equity Incentive Plan, effective January 1, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed May 17, 2017, File No. 001-08754).
10.11+	Form of Stock Option Agreement - Emergence Grant (Type I) (incorporated by reference as Exhibit 4.2 to SilverBow Resources Inc.'s Form S-8 filed April 27, 2016, File No. 333-210936).
10.12+	Form of Stock Option Agreement - Emergence Grant (Type II) (incorporated by reference as Exhibit 4.3 to SilverBow Resources Inc.'s Form S-8 filed April 27, 2016, File No. 333-210936).
10.13+	Form of Restricted Stock Unit Agreement - Emergence Grant (Type I) (incorporated by reference as Exhibit 4.4 to SilverBow Resources Inc.'s Form S-8 filed April 27, 2016, File No. 333-210936).
10.14+	Form of Restricted Stock Unit Agreement - Emergence Grant (Type II) (incorporated by reference as Exhibit 4.5 to SilverBow Resources Inc.'s Form S-8 filed April 27, 2016, File No. 333-210936).
10.15+	Form of Restricted Stock Unit Agreement - Non Employee Directors (incorporated by reference as Exhibit 10.1to SilverBow Resources Inc.'s Form 8-K filed June 14, 2016, File No. 001-08754)
10.16+	Form of Stock Option Agreement- Non Employee Directors (incorporated by reference as Exhibit 10.2 to SilverBow Resources Inc.'s Form 8-K filed June 14, 2016, File No. 001-08754).
10.17+	SilverBow Resources Inc. Inducement Plan (incorporated by reference as Exhibit 4.4 to SilverBow Resources, Inc.'s Form S-8 filed December 21, 2016, File No. 333-21535).
10.18+	First Amendment to SilverBow Resources, Inc. Inducement Plan, effective May 5, 2017 (incorporated by reference as Exhibit 10.2 to SilverBow Resources, Inc.'s Form 8-K filed May 5, 2017, File No. 001-08754).
10.19+	Form of Restricted Stock Unit Agreement - Inducement Plan (incorporated by reference as Exhibit 4.5 to SilverBow Resources Inc.'s Form S-8 filed December 21, 2016, File No. 333-21535).
10.20+	Form of Stock Option Agreement - Inducement Plan (incorporated by reference as Exhibit 4.6 to SilverBow Resources Inc.'s Form S-8 filed December 21, 2016, File No. 333-215235).
10.21+	Employment Agreement by and between SilverBow Resources, Inc. and Sean C. Woolverton, effective as of March 1, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed February 28, 2017, File No. 001-08754).
10.22+	Employment Agreement by and between SilverBow Resources, Inc. and G. Gleeson Van Riet, effective as of March 20, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed March 21, 2017, File No. 001-08754).
10.23+	Employment Agreement by and between SilverBow Resources, Inc. and Steven W. Adam, effective as of November 6, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed November 6, 2017, File No. 001-08754).

10.24+	Employment Agreement by and between SilverBow Resources, Inc. and Christopher M. Abundis, effective as of March 20, 2017 (incorporated by reference as Exhibit 10.1 to SilverBow Resources, Inc.'s Form 8-K filed March 21, 2017, File No. 001-08754).
10.25+	First Amended and Restated Executive Employment Agreement of Robert J. Banks dated April 22, 2016 (incorporated by reference as Exhibit 10.6 to SilverBow Resources's Form 8-K filed April 28, 2016, File No. 001-08754).
10.26+	Third Amended and Restated Executive Employment Agreement of Alton D. Heckaman, Jr. dated April 22, 2016 (incorporated by reference as Exhibit 10.7 to SilverBow Resources Inc.'s Form 8-K filed April 28, 2016, File No. 001-08754).
10.27+	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 SilverBow Resources, Inc.'s Form 8-K filed November 16, 2016, File No. 001-08754).
10.28+*	Form of Indemnity Agreement for SilverBow Resources, Inc. directors and officers.
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 SilverBow Resources, Inc.'s Form 8-K filed June 14, 2016, File No. 001-08754).
21 *	List of Subsidiaries of SilverBow Resources, Inc.
23.1 *	Consent of H.J. Gruy and Associates, Inc.
23.2 *	Consent of BDO USA, LLP as to incorporation by reference regarding Form S-3 and Form S-8 Registration Statements.
23.3*	Consent of Ernst & Young LLP as to incorporation by reference regarding Form S-3 and 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 26, 2018.
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, SilverBow Resources, Inc., has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 1, 2018.

SILVERBOW RESOURCES, INC.

By: /s/ Sean C. Woolverton

Sean C. Woolverton
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, SilverBow Resources, Inc., and in the capacities and on the dates indicated:

Signatures	Title	Date
/s/ Sean C. Woolverton Sean C. Woolverton	Chief Executive Officer	March 1, 2018
/s/ G. Gleeson Van Riet G. Gleeson Van Riet	Executive Vice President and Chief Financial Officer	March 1, 2018
/s/ Gary G. Buchta Gary G. Buchta	Controller	March 1, 2018
/s/Marcus C. Rowland Marcus C. Rowland	Chairman of the Board Director	March 1, 2018
/s/ Michael Duginski Michael Duginski	Director	March 1, 2018
/s/ Gabriel L. Ellisor Gabriel L. Ellisor	Director	March 1, 2018
/s/ David Geenberg David Geenberg	Director	March 1, 2018
/s/ Christoph O. Majeske Christoph O. Majeske	Director	March 1, 2018
/s/ Charles W. Wampler Charles W. Wampler	Director	March 1, 2018

(Back To Top)

Section 2: EX-10.2 (EXHIBIT 10.2)

Exhibit 10.2

FIRST AMENDMENT TO FIRST AMENDED AND RESTATED SENIOR SECURED REVOLVING CREDIT AGREEMENT

This FIRST AMENDMENT TO FIRST AMENDED AND RESTATED SENIOR SECURED REVOLVING CREDIT AGREEMENT (this "Amendment") dated as of November 9, 2017, is among SILVERBOW RESOURCES, INC. (f/k/a Swift Energy Company), a Delaware corporation (the "Borrower"), the undersigned guarantors (the "Guarantors" and, together with the Borrower, the "Obligors"), JPMORGAN CHASE BANK, N.A., as administrative agent for the Lenders (in such capacity, together with its successors, the "Administrative Agent"), and the Lenders.

Recitals

A. The Borrower, the Administrative Agent and the Lenders are parties to that certain First Amended and Restated Senior Secured Revolving Credit Agreement dated as of April 19, 2017 (the "Credit Agreement"), pursuant to which the Lenders have made certain credit available to and on behalf of the Borrower.

B. The Borrower has informed the Administrative Agent and Lenders that it intends to incur either (a) Permitted Second Lien Debt or (b) Permitted Unsecured Debt during the period commencing on the Amendment Effective Date (as defined below) and ending on December 31, 2017 (such period, the "Incurrence Window") in an aggregate principal amount of not less than $150.0 million and not greater than $200.0 million (the "Incurrence Range") (such Indebtedness if incurred during the Incurrence Window and in an aggregate principal amount within the Incurrence Range, the "Proposed Debt Incurrence").

C. The Borrower has requested, and the Administrative Agent and the Lenders have agreed subject to the terms and conditions herein to (a) increase the Borrowing Base to $370.0 million in connection with the Current Scheduled Redetermination (as defined below), (b) amend certain provisions of the Credit Agreement and (c) without prejudice to the other rights of the Administrative Agent and the Lenders under the Credit Agreement, (i) waive the application of Section 2.08(c) of the Credit Agreement in respect of the Proposed Debt Incurrence (the "Requested Borrowing Base Waiver") and (ii) in lieu of a reduction to the Borrowing Base pursuant to Section 2.08(c) of the Credit Agreement upon the Proposed Debt Incurrence, reduce the Borrowing Base by $40.0 million upon the Proposed Debt Incurrence (the "Requested Alternative Borrowing Base Adjustment").

D. NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

Section 1. Defined Terms. Each capitalized term used herein but not otherwise defined herein has the meaning given to such term in the Credit Agreement. Unless otherwise indicated, all section references in this Amendment refer to sections in the Credit Agreement.

Section 2. Amendments to Credit Agreement.

2.1 Amendments to Section 1.02.

(a) The following defined terms are hereby inserted in the Credit Agreement where alphabetically appropriate:

"NYFRB Rate" means, for any day, the greater of (a) the Federal Funds Effective Rate in effect on such day and (b) the Overnight Bank Funding Rate in effect on such day (or for any day that is not a Banking Day, for the immediately preceding Banking Day); provided that if none of such rates are published for any day that is a Business Day, the term "NYFRB Rate" means the rate for a federal funds transaction quoted at 11:00 a.m. on such day received to the Administrative Agent from a Federal funds broker of recognized standing selected by it; provided, further, that if any of the aforesaid rates shall be less than zero, such rate shall be deemed to be zero for purposes of this Agreement.

"Overnight Funding Rate" means, for any day, the rate comprised of both overnight federal funds and overnight Eurodollar borrowings by U.S.-managed banking offices of depository institutions, as such composite rate shall be determined by the Federal Reserve Bank of New York as set forth on its public website from time to time, and published on the next succeeding Business Day by the Federal Reserve Bank of New York as an overnight bank funding rate (from and after such date as the Federal Reserve Bank of New York shall commence to publish such composite rate).

(b) The following terms contained in Section 1.02 of the Credit Agreement are hereby amended and restated in their entirety with the following text:

(i) ""Alternate Base Rate" means, for any day, a rate per annum equal to the greatest of (a) the Prime Rate in effect on such day, (b) the NYFRB Rate in effect on such day plus ½ of 1% and (c) the Adjusted LIBO Rate for a one month Interest Period on such day (or if such day is not a Business Day, the immediately preceding Business Day) plus 1%, provided that for the purpose of this definition, the Adjusted LIBO Rate for any day shall be based on the LIBO Screen Rate (or if the LIBO Screen Rate is not available for such one month Interest Period, the Interpolated Rate) at approximately the Specified Time on such day. Any change in the Alternate Base Rate due to a change in the Prime Rate, the NYFRB Rate or the Adjusted LIBO Rate shall be effective from and including the effective date of such change in the Prime Rate, the NYFRB Rate or the Adjusted LIBO Rate, respectively. If the Alternate Base Rate is being used as an alternate rate of interest pursuant to Section 2.14 hereof, then the Alternate Base Rate shall be the greater of clause (a) and clause (b) above and shall be determined without reference to clause (c) above. For the avoidance of doubt, if the Alternate Base Rate shall be less than zero, such rate shall be deemed to be zero for purposes of this Agreement."

(ii) ""Federal Funds Effective Rate" means, for any day, the rate calculated by the Federal Reserve Bank of New York based on such day's federal funds transactions by depositary institutions (as determined in such manner as the Federal Reserve Bank of New York shall set forth on its public website from time to time) and published on the next succeeding Business Day by the Federal Reserve Bank of New York as the federal funds effective rate, provided that if the Federal Funds Effective Rate shall be less than zero, such rate shall be deemed to zero for the purposes of this Agreement."

2.2 Amendment to Section 3.03. Section 3.03 of the Credit Agreement is hereby amended and restated in its entirety with the following text:

“Section 3.03. Alternate Rate of Interest. If prior to the first day of any Interest Period:

(a) If prior to the first day of any Interest Period:

(i) the Administrative Agent determines (which determination shall be conclusive and binding absent manifest error) that adequate and reasonable means (including, without limitation, by means of an Interpolated Rate) do not exist for ascertaining the Adjusted LIBO Rate or the LIBO Rate, as applicable, for such Interest Period; or

(ii) the Administrative Agent shall have received notice from the Majority Lenders that the Adjusted LIBO Rate or LIBO Rate, as applicable, determined or to be determined for such Interest Period will not adequately and fairly reflect the cost to such Lenders (as conclusively certified by such Lenders) of making or maintaining their affected Loans included in such Borrowing for such Interest Period,

then the Administrative Agent shall give notice thereof to the Borrower and the Lenders by telephone as promptly as practicable thereafter and, until the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist, (i) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective (and such Borrowing shall be automatically converted into ABR Loans on the last day of the applicable Interest Period), and (ii) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made either as an ABR Borrowing.

(b) If any Lender determines that any requirement of law has made it unlawful, or if any Governmental Authority has asserted that it is unlawful, for any Lender or its applicable lending office to make, maintain, fund or continue any Eurodollar Borrowing, or any Governmental Authority has imposed material restrictions on the authority of such Lender to purchase or sell, or to take deposits of, dollars in the London interbank market, then, on notice thereof by such Lender to the Borrower through the Administrative Agent, any obligations of such Lender to make, maintain, fund or continue Eurodollar Loans or to convert ABR Borrowings to Eurodollar Borrowings will be suspended until such Lender notifies the Administrative Agent and the Borrower that the circumstances giving rise to such determination no longer exist. Upon receipt of such notice, the Borrower will upon demand from such Lender (with a copy to the Administrative Agent), either convert or prepay all Eurodollar Borrowings of such Lender to ABR Borrowings, either on the last day of the Interest Period therefor, if such Lender may lawfully continue to maintain such Eurodollar Borrowings to such day, or immediately, if such Lender may not lawfully continue to maintain such Loans. Upon any such conversion or prepayment, the Borrower will also pay accrued interest on the amount so converted or prepaid.

(c) If at any time the Administrative Agent determines (which determination shall be conclusive absent manifest error) that (i) the circumstances set forth in Section 3.03(a)(i) have arisen and such circumstances are unlikely to be temporary or (ii) the circumstances set forth in Section 3.03(a)(i) have not arisen but the supervisor for the administrator of the LIBO Screen Rate or a Governmental Authority having jurisdiction over the Administrative Agent has made a public statement identifying a specific date after which the LIBO Screen Rate shall no longer be used for determining interest rates for loans, then the Administrative Agent and the Borrower shall endeavor to establish an alternate rate of interest to the LIBO Rate that gives due consideration to the then prevailing market convention for determining a rate of interest for syndicated loans in the United States at such time, and shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable. Notwithstanding anything to the contrary in Section 12.02(b), such amendment shall become effective without any further action or consent of any other party to this Agreement so long as the Administrative Agent shall not have received, within five Business Days of the date notice of such alternate rate of interest is provided to the Lenders, a written notice from the Required Lenders stating that such Required Lenders object to such amendment. Until an alternate rate of interest shall be determined in accordance with this Section 3.03(c) (but, in the case of the circumstances described in Section 3.03(c)(ii), only to the extent the LIBO Screen Rate for such Interest Period is not available or published at such time on a current basis), (x) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a Eurodollar Borrowing shall be ineffective, and (y) if any Borrowing Request requests a Eurodollar Borrowing, such Borrowing shall be made as an ABR Borrowing; provided that, if such alternate rate of interest shall be less than zero, such rate shall be deemed to be zero for the purposes of this Agreement."

2.3 Amendment to Annex I. The Lenders have agreed to the assignment and reallocation certain Lenders' respective Commitments and Maximum Credit Amounts (the "Assigned Interests"). On the Amendment Effective Date and after giving effect to such reallocations, the Maximum Credit Amount and Applicable Percentage of each Lender shall be as set forth on Annex I attached hereto and the Borrower and each Lender hereby consents and agrees to the Maximum Credit Amount and Applicable Percentages set forth on such Annex I. With respect to such assignment and reallocation, each Lender acquiring Assigned Interests shall be deemed to have acquired its portion of the Assigned Interests allocated to it from each other Lenders from whom a disposition of Assignment Interests was necessary to achieve the Maximum Credit Amounts and Applicable Percentages set forth on such Annex I pursuant to the terms of an Assignment and Assumption attached as Exhibit G to the Credit Agreement as if each such Lender had executed the necessary Assignment and Assumptions with respect to such reallocation at par (it being understood that any other determinations made with respect to such reallocation shall be made by the Administrative Agent in its reasonable discretion in consultation with any such applicable Lenders and any such Lender and the Borrower shall promptly execute any customary assigned documentation needed or advisable to effectuate such reallocation if reasonably requested by the Administrative Agent). In connection with, and for the purposes of, the assignments and reallocations effected by this Amendment only, the Administrative Agent waives the processing and recordation fee under Section 12.04(b)(ii)(C).

Section 3. Borrowing Base. Each Lender, the Administrative Agent and the Borrower agree that upon and as of the Amendment Effective Date (as defined below): (a) the November 1, 2017 Scheduled Redetermination shall be deemed to have taken place according to the procedures set forth in the Credit Agreement and (b) the amount of the Borrowing Base shall be increased from $330.0 million to $370.0 million (the "Current Scheduled Redetermination"; such $40.0 million increase to the Borrowing Base, the "Borrowing Base Increase"). After giving effect to the Current Scheduled Redetermination and subject to Section 4 of this Amendment, the Borrowing Base shall remain in effect until otherwise redetermined or adjusted pursuant to the Borrowing Base Adjustment Provisions in accordance with the Credit Agreement. For avoidance of doubt, this provision does not limit the right of the parties to initiate Interim Redeterminations of the Borrowing Base in accordance with Section 2.07(c) of the Credit Agreement or any other Borrowing Base Adjustment Provisions (subject to Section 4 of this Amendment) and the Current Scheduled Redetermination shall not constitute an Interim Redetermination. This Section 3 constitutes the New Borrowing Base Notice delivered in accordance with Section 2.07(d) of the Credit Agreement in connection with the Current Scheduled Redetermination.

Section 4. Waiver. The Borrower, Administrative Agent and Lenders hereby agrees to (a) the Requested Borrowing Base Waiver and (b) the application of the Requested Alternative Borrowing Base

Adjustment in connection with consummation of the Proposed Debt Incurrence, subject to the following conditions subsequent:

(i) the Borrower incurs the Proposed Debt Incurrence within the Incurrence Window,

(ii) the aggregate principal amount of the Proposed Debt Incurrence is within the Incurrence Range, and

(iii) the Proposed Debt Incurrence constitutes (A) Permitted Second Lien Debt if the Proposed Debt Incurrence is secured and (B) Permitted Unsecured Debt if the Proposed Debt Incurrence is unsecured.

For avoidance of doubt, this provision does not limit the right of the parties to initiate Interim Redeterminations of the Borrowing Base in accordance with Section 2.07(c) or any other Borrowing Base Adjustment Provisions.

In the event that the Borrower fails to incur such Proposed Debt Incurrence within the Incurrence Window, then the Borrower shall pay to the Administrative Agent on behalf of the Lenders, a commitment increase fee in an amount equal to 67.5 basis points multiplied by the Borrowing Base Increase, which fee shall due and payable by the Borrower on the first Business Day after the last day of the Incurrence Window and which fee shall be allocated among the Lenders based on their respective percentage shares of the Borrowing Base Increase.

Section 5. Conditions Precedent. This Amendment shall become effective on the date (such date, the "Amendment Effective Date") when each of the following conditions is satisfied (or waived in accordance with Section 12.02(b) of the Credit Agreement):

5.1 The Administrative Agent, the Arranger and the Lenders shall have received all other fees and other amounts due and payable in connection with this Amendment or any other Loan Document on or prior to the Amendment Effective Date, including, to the extent invoiced, reimbursement or payment of all out-of-pocket expenses required to be reimbursed or paid by the Borrower pursuant to this Amendment or any other Loan Document.

5.2 The Administrative Agent shall have received a counterpart of this Amendment signed by the Borrower, the Guarantors and each Lender.

5.3 The Administrative Agent shall have received a certificate of a Responsible Officer of the Borrower certifying as to the representations and warranties in Section 6.2(d) below.

The Administrative Agent is hereby authorized and directed to declare this Amendment to be effective (and the Amendment Effective Date shall occur) when it has received documents confirming or certifying, to the satisfaction of the Administrative Agent, compliance with the conditions set forth in this Section 5 (or the waiver of such conditions as permitted in Section 12.02(b) of the Credit Agreement). Such declaration shall be final, conclusive and binding upon all parties to the Credit Agreement for all purposes.

Section 6. Miscellaneous.

6.1 Confirmation. All of the terms and provisions of the Credit Agreement, as amended and waived by this Amendment, are, and shall remain, in full force and effect following the effectiveness of this

Amendment. Neither the execution by the Administrative Agent or the Lenders of this Amendment, nor any other act or omission by the Administrative Agent or the Lenders or their officers in connection herewith, shall be deemed to be an agreement by the Administrative Agent or the Lenders to agree to any future requests in respect of a Scheduled Redetermination or otherwise.

6.2 Ratification and Affirmation; Representations and Warranties. Each Obligor hereby (a) acknowledges the terms of this Amendment; (b) ratifies and affirms (i) its obligations under, and acknowledges, renews and extends its continued liability under, each Loan Document and agrees that each Loan Document remains in full force and effect as expressly amended hereby and (ii) that the Liens created by the Loan Documents to which it is a party are valid and continuing and secure the Secured Obligations in accordance with the terms thereof, after giving effect to this Amendment; (c) agrees that from and after the Amendment Effective Date (i) each reference to the Credit Agreement in the other Loan Documents shall be deemed to be a reference to the Credit Agreement, as amended and waived by this Amendment and (ii) this Amendment does not constitute a novation of the Credit Agreement; and (d) represents and warrants to the Lenders that as of the date hereof, and immediately after giving effect to the terms of this Amendment: (i) all of the representations and warranties contained in each Loan Document are true and correct in all material respects (unless already qualified by materiality in which case such applicable representation and warranty shall be true and correct), except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects (unless already qualified by materiality in which case such applicable representation and warranty shall be true and correct) as of such specified earlier date, (ii) no Default or Event of Default has occurred and is continuing (including under Section 8.01(k), Section 8.13(b) and Section 8.02(d) of the Credit Agreement) and (iii) no event, development or circumstance has occurred or exists that has resulted in, or could reasonably be expected to have, a Material Adverse Effect.

6.3 Loan Document. This Amendment is a Loan Document.

6.4 Counterparts. This Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed counterpart of a signature page of this Amendment by facsimile or email transmission shall be effective as delivery of a manually executed counterpart of this Amendment.

6.5 No Oral Agreement. This Amendment, the Credit Agreement and the other Loan Documents executed in connection herewith and therewith represent the final agreement between the parties and may not be contradicted by evidence of prior, contemporaneous, or unwritten oral agreements of the parties. There are no subsequent oral agreements between the parties.

6.6 GOVERNING LAW. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK. Section 12.09(b)-(d) of the Credit Agreement shall be incorporated herein in *mutatis mutandis*.

6.7 Successors and Assigns. This Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns.

6.8 No Claims. Each Obligor represents and warrants that as of the date of this Amendment, it has no knowledge of events or circumstances that would reasonably be expected to give rise to a claim against any Lender or the Administrative Agent.

[*Signature Pages Follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed as of the date first written above.

BORROWER:**SILVERBOW RESOURCES, INC.**

By: __/s/ G. Gleeson Van Riet____________
Name: G. Gleeson Van Riet
Title: Executive Vice President and Chief Financial Officer

GUARANTOR:**SILVERBOW RESOURCES OPERATING, LLC**

By: __/s/ G. Gleeson Van Riet____________
Name: G. Gleeson Van Riet
Title: Executive Vice President, Chief Financial Officer and Treasurer

GUARANTOR:**SILVERBOW RESOURCES USA, INC.**

By: __/s/ G. Gleeson Van Riet____________
Name: G. Gleeson Van Riet
Title: Vice President, Chief Financial Officer and Treasurer

ADMINISTRATIVE AGENT: **JPMORGAN CHASE BANK, N.A.**, as Administrative Agent and a Lender

By: ___/s/ Jo Linda Papadakis___________
Name: Jo Linda Papadakis
Title: Authorized Officer

LENDER: **COMPASS BANK**, as a Lender

By: __/s/ Daniel Ferreyra ________________
Name: Daniel Ferreyra
Title: Vice President

LENDER: **SUNTRUST BANK**, as a Lender

By: __/s/ Benjamin L. Brown ________________
Name: Benjamin L. Brown
Title: Director

LENDER: **[*]**, as a Lender

BOKF, NA dba Bank of Texas

By: __/s/ Martin W. Wilson _______________
Name: Martin W. Wilson
Title: Senior Vice President

LENDER: **Canadian Imperial Bank of Commerce, New York Branch**, as a Lender

By: __/s/ Richard Antl _______________
Name: Richard Antl
Title: Authorized Signatory

By: __/s/ Trudy Nelson _______________
Name: Trudy Nelson
Title: Authorized Signatory

LENDER: **FIFTH THIRD BANK**, as a Lender

By: __/s/ Justin Bellamy ________________
Name: Justin Bellamy
Title: Director

LENDER: **BRANCH BANKING AND TRUST**, as a Lender

By: __/s/ Kelly Graham ______________

Name: Kelly Graham

Title: Vice President

LENDER: **COMERCIA BANK**, as a Lender

By: __/s/ Jason M. Klesel _______________
Name: Jason M. Klesel
Title: Assistant Vice President

LENDER:

Credit Suisse AG, Cayman Islands Branch, as a Lender

By: __/s/ Nupur Kumar ________________
Name: Nupur Kumar
Title: Authorized Signatory

By: __/s/ Christopher Zybrick ___________
Name: Christopher Zybrick
Title: Authorized Signatory

LENDER: **KeyBank, National Association**, as a Lender

By: __/s/ George E. McKean ____________
Name: George E. McKean
Title: Senior Vice President

LENDER: **Associated Bank, N.A.**, as a Lender

By: __/s/ Ryan Osborn _______________
Name: Ryan Osborn
Title: AVP

LENDER: **Whitney Bank**, as a Lender

By: __/s/ William Jochetz ________________
Name: William Jochetz
Title: Vice President

ANNEX I

LIST OF MAXIMUM CREDIT AMOUNTS

Aggregate Maximum Credit Amounts

Name of Lender	Applicable Percentage	Maximum Credit Amount
JPMORGAN CHASE BANK, N.A.	10.67567567333330%	$64,054,054.04
COMPASS BANK	9.18918919000000%	$55,135,135.14
SUNTRUST BANK	9.18918919000000%	$55,135,135.14
BOKF, N.A. DBA BANK OF TEXAS	9.18918919000000%	$55,135,135.14
CANADIAN IMPERIAL BANK OF COMMERCE, NEW YORK BRANCH	9.18918919000000%	$55,135,135.14
FIFTH THIRD BANK	9.18918919000000%	$55,135,135.14
BRANCH BANKING AND TRUST COMPANY	8.37837837833334%	$50,270,270.27
COMERICA BANK	8.37837837833334%	$50,270,270.27
CREDIT SUISSE AG, CAYMAN ISLANDS BRANCH	8.37837837833334%	$50,270,270.27
KEYBANK N.A.	7.43243243166667%	$44,594,594.59
ASSOCIATED BANK, N.A.	5.40540540500000%	$32,432,432.43
WHITNEY BANK	5.40540540500000%	$32,432,432.43
TOTAL	**100.00000000000000%**	$600,000,000.00

(Back To Top)

Section 3: EX-10.28 (EXHIBIT 10.28)

EXHIBIT 10.28

DIRECTOR AND OFFICER INDEMNIFICATION AGREEMENT

This Director and Officer Indemnification Agreement, dated as of **_________________**, 201**_** (this "***Agreement***"), is made by and between SilverBow Resources, Inc., a Delaware corporation (the “***Company***”), and __________________ (“***Indemnitee***”).

RECITALS:

A. Section 141 of the Delaware General Corporation Law provides that the business and affairs of a corporation shall be managed by or under the direction of its board of directors.

B. Pursuant to Sections 141 and 142 of the Delaware General Corporation Law, significant authority with respect to the management of the Company has been delegated to the officers of the Company.

C. By virtue of the managerial prerogatives vested in the directors and officers of a Delaware corporation, directors and officers act as fiduciaries of the corporation and its stockholders.

D. Thus, it is critically important to the Company and its stockholders that the Company be able to attract and retain the most capable persons reasonably available to serve as directors and officers of the Company.

E. In recognition of the need for corporations to be able to induce capable and responsible persons to accept positions in corporate management, Delaware law authorizes (and in some instances requires) corporations to indemnify their directors and officers, and further authorizes corporations to purchase and maintain insurance for the benefit of their directors and officers.

F. The Delaware courts have recognized that indemnification by a corporation serves the dual policies of (1) allowing corporate officials to resist unjustified lawsuits, secure in the knowledge that, if vindicated, the corporation will bear the expense of litigation and (2) encouraging capable women and men to serve as corporate directors and officers, secure in the knowledge that the corporation will absorb the costs of defending their honesty and integrity.

G. Delaware law also authorizes a corporation to pay in advance of the final disposition of an action, suit or proceeding the expenses incurred by a director or officer in the defense thereof, and any such right to the advancement of expenses may be made separate and distinct from any right to indemnification and need not be subject to the satisfaction of any standard of conduct or otherwise affected by the merits of any claims against the director or officer.

H. The number of lawsuits challenging the judgment and actions of directors and officers of Delaware corporations, the costs of defending those lawsuits, and the threat to directors’ and officers’ personal assets have all materially increased over the past several years, chilling the willingness of capable women and men to undertake the responsibilities imposed on corporate directors and officers.

I. Recent federal legislation and rules adopted by the Securities and Exchange Commission and the national securities exchanges have imposed additional disclosure and corporate governance obligations on directors and officers of public companies and have exposed such directors and officers to new and substantially broadened civil liabilities.

J. These legislative and regulatory initiatives have also exposed directors and officers of public companies to a significantly greater risk of criminal proceedings, with attendant defense costs and potential criminal fines and penalties.

K. The authority of a corporation to indemnify and advance the costs of defense to its directors and officers applies to criminal proceedings as well as to civil, administrative and investigative proceedings.

L. Indemnitee is a director or officer of the Company and his or her willingness to serve in such capacity is predicated, in substantial part, upon the Company's willingness to indemnify him or her in accordance with the principles reflected above, to the fullest extent permitted by the laws of the state of Delaware, and upon the other undertakings set forth in this Agreement.

M. Therefore, in recognition of the need to provide Indemnitee with substantial protection against personal liability, in order to procure Indemnitee's continued service as a director or officer of the Company and to enhance Indemnitee's ability to serve the Company in an effective manner, and in order to provide such protection pursuant to express contract rights (intended to be enforceable irrespective of, among other things, any amendment to the Company's certificate of incorporation or bylaws (collectively, the "***Constituent Documents***"), any change in the composition of the Company's Board of Directors (the "***Board***") or any change-in-control or business combination transaction relating to the Company), the Company wishes to provide in this Agreement for the indemnification of and the advancement of Expenses (as defined in Section 1(e)) to Indemnitee as set forth in this Agreement and for the continued coverage of Indemnitee under the Company's directors' and officers' liability insurance policies.

N. In light of the considerations referred to in the preceding recitals, it is the Company's intention and desire that the provisions of this Agreement be construed liberally, subject to their express terms, to maximize the protections to be provided to Indemnitee hereunder.

AGREEMENT:

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereby agree as follows:

1. Certain Definitions. In addition to terms defined elsewhere herein, the following terms have the following meanings when used in this Agreement with initial capital letters:

(a) "***Claim***" means (i) any threatened, asserted, pending or completed claim, demand, action, suit or proceeding, whether civil, criminal, administrative, arbitrative, investigative or other, and whether made pursuant to federal, state or other law; and (ii) any threatened, pending or completed inquiry or investigation, whether made, instituted or conducted by or at the behest of the Company or any other person, including any federal, state or other court or governmental entity or agency and any committee or other representative of any corporate constituency, that Indemnitee determines might lead to the institution of any such claim, demand, action, suit or proceeding.

(b) "***Controlled Affiliate***" means any corporation, limited liability company, partnership, joint venture, trust or other entity or enterprise, whether or not for profit, that is directly or indirectly controlled by the Company. For purposes of this definition, "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of an entity or enterprise, whether through the ownership of voting securities, through other voting rights, by contract or otherwise; *provided* that direct or indirect beneficial ownership of capital stock or other interests in an entity or enterprise entitling the holder to cast 20% or more of the total number of votes generally entitled to be cast in the election of directors (or persons performing comparable functions) of such entity or enterprise shall be deemed to constitute control for purposes of this definition.

(c) "***Disinterested Director***" means a director of the Company who is not and was not a party to the Claim in respect of which indemnification is sought by Indemnitee.

(d) "***ERISA Losses***" means any taxes, penalties or other liabilities under the Employee Retirement Income Security Act of 1974, as amended, or Section 4975 of the Internal Revenue Code of 1986, as amended.

(e) "***Expenses***" means attorneys' and experts' fees and expenses and all other costs and expenses paid or payable in connection with investigating, defending, being a witness in or participating in (including on appeal), or preparing to investigate, defend, be a witness in or participate in (including on appeal), any Claim, other than the fees, expenses and costs in respect of which the Company is expressly stated in Section 15 to have no obligation.

(f) "***Incumbent Directors***" means the individuals who, as of the date hereof, are members of the Board and any individual becoming a member of the Board subsequent to the date hereof whose election, nomination for election by the Company's stockholders, or appointment, was approved by a vote of at least two-thirds of the then Incumbent Directors (either by a specific vote or by approval of the proxy statement of the Company in which such person is named as a nominee for director, without objection to such nomination); *provided*, *however*, that an individual shall not be an Incumbent Director if such individual's election or appointment to the Board occurs as a result of an actual or threatened election contest (as described in Rule 14a-12(c) of the Securities Exchange Act of 1934, as amended) with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board.

(g) "***Indemnifiable Claim***" means any Claim based upon, arising out of or resulting from (i) any actual, alleged or suspected act or failure to act by Indemnitee in his or her capacity as a director, officer, employee or agent of the Company or as a director, officer, employee, member, manager, trustee or agent of any other corporation, limited liability company, partnership, joint venture, trust or other entity or enterprise, whether or not for profit (including any employee benefit plan or related trust), as to which Indemnitee is or was serving at the request of the Company as a director, officer, employee, member, manager, trustee or agent, (ii) any actual, alleged or suspected act or failure to act by Indemnitee in respect of any business, transaction, communication, filing, disclosure or other activity of the Company or any other entity or enterprise referred to in clause (i) of this sentence, or (iii) Indemnitee's status as a current or former director, officer, employee or agent of the Company or as a current or former director, officer, employee, member, manager, trustee or agent of the Company or any other entity or enterprise referred to in clause (i) of this sentence or any actual, alleged or suspected act or failure to act by Indemnitee in connection with any obligation or restriction imposed upon Indemnitee by reason of such status; *provided*, *however*, that except for compulsory counterclaims, Indemnifiable Claim shall not include any Claim initiated by Indemnitee against the Company or any director or officer of the Company unless (1) the Incumbent Directors consented to the initiation of such Claim prior to its initiation, (2) the Incumbent Directors authorize the Company to join in such Claim, or (3) such Claim is initiated solely to enforce Indemnitee's rights under this Agreement. In addition to any service at the actual request of the Company, for purposes of this Agreement, Indemnitee shall be deemed to be serving or to have served at the request of the Company as a director, officer, employee, member, manager, trustee or agent of another entity or enterprise if Indemnitee is or was serving as a director, officer, employee, member, manager, trustee or agent of such entity or enterprise and (i) such entity or enterprise is or at the time of such service was a Controlled Affiliate, (ii) such entity or enterprise is or at the time of such service was an employee benefit plan (or related trust) sponsored or maintained by the Company or a Controlled Affiliate, or (iii) the Company or a Controlled Affiliate directly or indirectly caused or authorized Indemnitee to be nominated, elected, appointed, designated, employed, engaged or selected to serve in such capacity.

(h) "***Indemnifiable Losses***" means any and all Losses relating to, arising out of or resulting from any Indemnifiable Claim.

(i) "***Independent Counsel***" means a law firm, or a member of a law firm, that is experienced in matters of corporation law and neither presently is, nor in the past five years has been, retained to represent: (i) the Company (or any Subsidiary) or Indemnitee in any matter material to either such party (other than with respect to matters concerning Indemnitee under this Agreement, or of other indemnitees under similar indemnification agreements), or (ii) any other named (or, as to a threatened matter, reasonably likely to be named) party to the Indemnifiable Claim giving rise to a claim for indemnification hereunder. Notwithstanding the foregoing, the term "Independent Counsel" shall not include any person who, under the applicable standards of professional conduct then prevailing, would have a conflict of interest in representing either the Company or Indemnitee in an action to determine Indemnitee's rights under this Agreement.

(j) "***Losses***" means any and all Expenses, damages, losses, liabilities, judgments, fines, penalties (whether civil, criminal or other), ERISA Losses and amounts paid in settlement, including all interest, assessments and other charges paid or payable in connection with or in respect of any of the foregoing.

(k) "***Subsidiary***" means an entity in which the Company directly or indirectly beneficially owns 50% or more of the outstanding Voting Stock.

(l) “***Voting Stock***” means securities entitled to vote generally in the election of directors (or similar governing bodies).

2. Indemnification Obligation. Subject to Section 8, the Company shall indemnify and hold harmless Indemnitee, to the fullest extent permitted or required by the laws of the State of Delaware in effect on the date hereof or as such laws may from time to time hereafter be amended to increase the scope of such permitted or required indemnification, against any and all Indemnifiable Claims and Indemnifiable Losses; provided, however, that no repeal or amendment of any law of the State of Delaware shall in any way diminish or adversely affect the rights of Indemnitee pursuant to this Agreement in respect of any occurrence or matter arising prior to any such repeal or amendment.

3. Advancement of Expenses. Indemnitee shall have the right to advancement by the Company prior to the final disposition of any Indemnifiable Claim of any and all Expenses relating to, arising out of or resulting from any Indemnifiable Claim paid or incurred by Indemnitee or which Indemnitee determines are reasonably likely to be paid or incurred by Indemnitee. Indemnitee’s right to such advancement is not subject to the satisfaction of any standard of conduct and is not conditioned upon any prior determination that Indemnitee is entitled to indemnification under this Agreement with respect to the Indemnifiable Claim or the absence of any prior determination to the contrary. Without limiting the generality or effect of the foregoing, within five business days after any request by Indemnitee, the Company shall, in accordance with such request (but without duplication), (a) pay such Expenses on behalf of Indemnitee, (b) advance to Indemnitee funds in an amount sufficient to pay such Expenses, or (c) reimburse Indemnitee for such Expenses; provided that Indemnitee shall repay, without interest any amounts actually advanced to Indemnitee that, at the final disposition of the Indemnifiable Claim to which the advance related, were in excess of amounts paid or payable by Indemnitee in respect of Expenses relating to, arising out of or resulting from such Indemnifiable Claim. In connection with any such payment, advancement or reimbursement, if delivery of an undertaking is a legally required condition precedent to such payment, advance or reimbursement or is otherwise requested by the Company, Indemnitee shall execute and deliver to the Company an undertaking in the form attached hereto as Exhibit A (subject to Indemnitee filling in the blanks therein and selecting from among the bracketed alternatives therein), which need not be secured and shall be accepted by the Company without reference to Indemnitee’s ability to repay the Expenses. In no event shall Indemnitee’s right to the payment, advancement or reimbursement of Expenses pursuant to this Section 3 be conditioned upon any undertaking that is less favorable to Indemnitee than, or that is in addition to, the undertaking set forth in Exhibit A.

4. Indemnification for Additional Expenses. Without limiting the generality or effect of the foregoing, the Company shall indemnify and hold harmless Indemnitee against and, if requested by Indemnitee, shall reimburse Indemnitee for, or advance to Indemnitee, within five business days of such request, any and all Expenses paid or incurred by Indemnitee or which Indemnitee determines are reasonably likely to be paid or incurred by Indemnitee in connection with any Claim made, instituted or conducted by Indemnitee, in each case to the fullest extent permitted or required by the laws of the State of Delaware in effect on the date hereof or as such laws may from time to time hereafter be amended to increase the scope of such permitted or required indemnification, reimbursement or advancement of such Expenses, for (a) indemnification or payment, advancement or reimbursement of Expenses by the Company under any provision of this Agreement, or under any other agreement or provision of the Constituent Documents now or hereafter in effect relating to Indemnifiable Claims, and/or (b) recovery under any directors' and officers' liability insurance policies maintained by the Company; provided, however, that Indemnitee shall return, without interest, any such advance of Expenses (or portion thereof) which remains unspent at the final disposition of the Claim to which the advance related.

5. Contribution. To the fullest extent permissible under applicable law in effect on the date hereof or as such law may from time to time hereafter be amended to increase the scope of permitted or required indemnification, if the indemnification provided for in this Agreement is unavailable to Indemnitee for any reason whatsoever, the Company, in lieu of indemnifying Indemnitee, shall contribute to the payment of any and all Indemnifiable Claims or Indemnifiable Losses, in such proportion as is fair and reasonable in light of all of the circumstances in order to reflect (i) the relative benefits received by the Company and Indemnitee as a result of the event(s) and/or transaction(s) giving cause to such Indemnifiable Claim or Indemnifiable Loss and/or (ii) the relative fault of the Company (and its other directors, officers, employees and agents) and Indemnitee in connection with such event(s) and/or transaction(s); provided that such contribution shall not be required where it is determined, pursuant to a final disposition of such Indemnifiable Claim or Indemnifiable Loss in accordance with Section 8, that Indemnitee is not entitled to indemnification by the Company with respect to such Indemnifiable Claim or Indemnifiable Loss. The Company will indemnify and hold harmless Indemnitee from any claim of contribution that may be brought by directors, officers, employees or other agents or representatives of the Company, other than Indemnitee, who may be jointly liable with Indemnitee.

6. Partial Indemnity. If Indemnitee is entitled under any provision of this Agreement to indemnification by the Company for some or a portion of any Indemnifiable Loss, but not for all of the total amount thereof, the Company shall nevertheless indemnify Indemnitee for the portion thereof to which Indemnitee is entitled.

7. Procedure for Notification. To obtain indemnification under this Agreement in respect of an Indemnifiable Claim or Indemnifiable Loss, Indemnitee shall submit to the Company a written request therefor, including a brief description (based upon information then available to Indemnitee) of such Indemnifiable Claim or Indemnifiable Loss. If, at the time of the receipt of such request, the Company has directors' and officers' liability insurance in effect under which coverage for such Indemnifiable Claim or Indemnifiable Loss is potentially available, the Company shall give prompt written notice of such Indemnifiable Claim or Indemnifiable Loss to the applicable insurers in accordance with the procedures set forth in the applicable policies. The Company shall provide to Indemnitee a copy of such notice delivered to the applicable insurers, and copies of all subsequent correspondence between the Company and such insurers regarding the Indemnifiable Claim or Indemnifiable Loss, in each case substantially concurrently with the delivery or receipt thereof by the Company. If requested by Indemnitee, the Company shall use its reasonable best efforts, at the Company's expense, to enforce on behalf of and for the benefit of Indemnitee all rights (including rights to receive payment) that may exist under the applicable policies of insurance in relation to such Indemnifiable Claim or Indemnifiable Loss. The failure by Indemnitee to timely notify the Company of any Indemnifiable Claim or Indemnifiable Loss shall not relieve the Company from any liability hereunder unless, and only to the extent that, the Company did not otherwise learn of such Indemnifiable Claim or Indemnifiable Loss and such failure results in forfeiture by the Company of substantial defenses, rights or insurance coverage.

8. Determination of Right to Indemnification.

(a) To the extent that Indemnitee shall have been successful on the merits or otherwise in defense of any Indemnifiable Claim or any portion thereof or in defense of any issue or matter therein, including dismissal without prejudice, Indemnitee shall be indemnified against Indemnifiable Losses relating to, arising out of or resulting from such Indemnifiable Claim in accordance with Section 2 and no Standard of Conduct Determination (as defined in Section 8(b)) shall be required with respect to such Indemnifiable Claim.

(b) To the extent that the provisions of Section 8(a) are inapplicable to an Indemnifiable Claim that shall have been finally disposed of, any determination of whether Indemnitee has satisfied any applicable standard of conduct under Delaware law that is a legally required condition precedent to indemnification of Indemnitee hereunder against Indemnifiable Losses relating to, arising out of or resulting from such Indemnifiable Claim (a "***Standard of Conduct Determination***") shall be made as follows: (i) by a majority vote of the Disinterested Directors, even if less than a quorum of the Board, (ii) if such Disinterested Directors so direct, by a majority vote of a committee of Disinterested Directors designated by a majority vote of all Disinterested Directors, or (iii) if there are no such Disinterested Directors or if Indemnitee so requests, by Independent Counsel, selected by the Indemnitee and approved by the Board (such approval not to be unreasonably withheld, delayed or conditioned), in a written opinion addressed to the Board, a copy of which shall be delivered to Indemnitee; provided, however, that if at the time of any Standard of Conduct Determination Indemnitee is neither a director nor an officer of the Company, such Standard of Conduct Determination may be made by or in the manner specified by the Board, any duly authorized committee of the Board or any duly authorized officer of the Company (unless Indemnitee requests that such Standard of Conduct Determination be made by Independent Counsel, in which case such Standard of Conduct Determination shall be made by Independent Counsel). Indemnitee will cooperate with the person or persons making such Standard of Conduct Determination, including providing to such person or persons, upon reasonable advance request, any documentation or information which is not privileged or otherwise protected from disclosure and which is reasonably available to Indemnitee and reasonably necessary to such determination. The Company shall indemnify and hold harmless Indemnitee against and, if requested by Indemnitee, shall reimburse Indemnitee for, or advance to Indemnitee, within five business days of such request, any and all costs and expenses (including attorneys' and experts' fees and expenses) incurred by Indemnitee in so cooperating with the person or persons making such Standard of Conduct Determination.

(c) The Company shall use its reasonable efforts to cause any Standard of Conduct Determination required under Section 8(b) to be made as promptly as practicable. If (i) the person or persons empowered or selected under Section 8 to make the Standard of Conduct Determination shall not have made a determination within 30 days after the later of (A) receipt by the Company of written notice from Indemnitee advising the Company of the final disposition of the applicable Indemnifiable Claim (the date of such receipt being the "***Notification Date***") and (B) the selection of an Independent Counsel, if such determination is to be made by Independent Counsel, and (ii) Indemnitee shall have fulfilled his or her obligations set forth in the second sentence of Section 8(b), then Indemnitee shall be deemed to have satisfied the applicable standard of conduct; *provided* that such 30-day period may be extended for a reasonable time, not to exceed an additional 30 days, if the person or persons making such determination in good faith requires such additional time for obtaining or evaluating any documentation or information relating thereto.

(d) If (i) Indemnitee shall be entitled to indemnification hereunder against any Indemnifiable Losses pursuant to Section 8(a), (ii) no determination of whether Indemnitee has satisfied any applicable standard of conduct under Delaware law is a legally required condition precedent to indemnification of Indemnitee hereunder against any Indemnifiable Losses, or (iii) Indemnitee has been determined or deemed pursuant to Section 8(b) or (c) to have satisfied any applicable standard of conduct under Delaware law which is a legally required condition precedent to indemnification of Indemnitee hereunder against any Indemnifiable Losses, then the Company shall pay to Indemnitee, within five business days after the later of (x) the Notification Date in respect of the Indemnifiable Claim or portion thereof to which such Indemnifiable Losses are related, out of which such Indemnifiable Losses arose or from which such Indemnifiable Losses resulted and (y) the earliest date on which the applicable criterion specified in clause (i), (ii) or (iii) above shall have been satisfied, an amount equal to the amount of such Indemnifiable Losses.

9. Presumption of Entitlement.

(a) In making a determination of whether Indemnitee has been successful on the merits or otherwise in defense of any Indemnifiable Claim or any portion thereof or in defense of any issue or matter therein, the Company acknowledges that a resolution, disposition or outcome short of dismissal or final judgment, including outcomes that permit Indemnitee to avoid expense, delay, embarrassment, injury to reputation, distraction, disruption or uncertainty, may constitute such success. In the event that any Indemnifiable Claim or any portion thereof or issue or matter therein is resolved or disposed of in any manner other than by adverse judgment against Indemnitee (including any resolution or disposition thereof by means of settlement with or without payment of money or other consideration), it shall be presumed that Indemnitee has been successful on the merits or otherwise in defense of such Indemnifiable Claim or portion thereof or issue or matter therein. The Company may overcome such presumption only by its adducing clear and convincing evidence to the contrary.

(b) In making any Standard of Conduct Determination, the person or persons making such determination shall presume that Indemnitee has satisfied the applicable standard of conduct, and the Company may overcome such presumption only by its adducing clear and convincing evidence to the contrary. The knowledge and/or action, or failure to act, of any director, officer, employee, agent or representative of the Company will not be imputed to Indemnitee for purposes of any Standard of Conduct Determination. Any Standard of Conduct Determination that Indemnitee has satisfied the applicable standard of conduct shall be final and binding in all respects, including with respect to any litigation or other action or proceeding initiated by Indemnitee to enforce his or her rights hereunder. Any Standard of Conduct Determination that is adverse to Indemnitee may be challenged by Indemnitee in the Court of Chancery of the State of Delaware. No determination by the Company (including by its directors or any Independent Counsel) that Indemnitee has not satisfied any applicable standard of conduct shall be a defense to any Claim by Indemnitee for indemnification or reimbursement or advance payment of Expenses by the Company hereunder or create a presumption that Indemnitee has not met any applicable standard of conduct.

(c) Without limiting the generality or effect of Section 9(b), (i) to the extent that any Indemnifiable Claim relates to any entity or enterprise (other than the Company) referred to in clause (i) of the first sentence of the definition of "Indemnifiable Claim," Indemnitee shall be deemed to have satisfied the applicable standard of conduct if Indemnitee acted in good faith and in a manner Indemnitee reasonably believed to be in or not opposed to the interests of such entity or enterprise (or the owners or beneficiaries thereof, including in the case of any employee benefit plan the participants and beneficiaries thereof) and, with respect to any criminal action or proceeding, had no reasonable cause to believe that his or her conduct was unlawful, and (ii) in all cases, any belief of Indemnitee that is based on the records or books of account of the Company, including financial statements, or on information supplied to Indemnitee by the directors or officers of the Company in the course of their duties, or on the advice of legal counsel for the Company, the Board, any committee of the Board or any director, or on information or records given or reports made to the Company, the Board, any committee of the Board or any director by an independent certified public accountant or by an appraiser or other expert selected by or on behalf of the Company, the Board, any committee of the Board or any director shall be deemed to be reasonable.

10. No Adverse Presumption. For purposes of this Agreement, the termination of any Claim by judgment, order, settlement (whether with or without court approval) or conviction, or upon a plea of *nolo contendere* or its equivalent, will not create a presumption that Indemnitee did not meet any applicable standard of conduct or that indemnification hereunder is otherwise not permitted.

11. Non-Exclusivity. The rights of Indemnitee hereunder will be in addition to any other rights Indemnitee may have against the Company under the Constituent Documents, or the substantive laws of the Company's jurisdiction of incorporation, any other contract or otherwise (collectively, "***Other Indemnity Provisions***"); *provided*, *however*, that (a) to the extent that Indemnitee otherwise would have any greater right to indemnification under any Other Indemnity Provision, Indemnitee will be deemed to have such greater right hereunder and (b) to the extent that any change is made to any Other Indemnity Provision which permits any greater right to indemnification than that provided under this Agreement as of the date hereof, Indemnitee will be deemed to have such greater right hereunder. The Company will not adopt any amendment to any of the Constituent Documents the effect of which would be to deny, diminish or encumber Indemnitee's right to indemnification under this Agreement or any Other Indemnity Provision.

12. Liability Insurance and Funding. For the duration of Indemnitee's service as a director and/or officer of the Company, and thereafter for so long as Indemnitee shall be subject to any pending or possible Indemnifiable Claim, the Company shall use reasonable efforts (taking into account the scope and amount of coverage available relative to the cost thereof) to cause to be maintained in effect policies of directors' and officers' liability insurance providing coverage for directors and/or officers of the Company that is at least substantially comparable in scope and amount to that provided by the Company's current policies of directors' and officers' liability insurance. At Indemnitee's request, the Company shall provide Indemnitee with a copy of all directors' and officers' liability insurance applications, binders, policies, declarations, endorsements and other related materials, and shall provide Indemnitee with a reasonable opportunity to review and comment on the same. Without limiting the generality or effect of the two immediately preceding sentences, the Company shall not discontinue or significantly reduce the scope or amount of coverage from one policy period to the next (i) without the prior approval thereof by a majority vote of the Incumbent Directors, even if less than a quorum, or (ii) if at the time that any such discontinuation or significant reduction in the scope or amount of coverage is proposed there are no Incumbent Directors, without the prior written consent of Indemnitee (which consent shall not be unreasonably withheld, delayed or conditioned). In all policies of directors' and officers' liability insurance obtained by the Company, Indemnitee shall be named as an insured in such a manner as to provide Indemnitee the same rights and benefits, subject to the same limitations, as are accorded to the Company's directors and officers most favorably insured by such policy. The Company may, but shall not be required to, create a trust fund, grant a security interest or use other means, including a letter of credit, to ensure the payment of such amounts as may be necessary to satisfy its obligations to indemnify and advance expenses pursuant to this Agreement.

13. Subrogation. In the event of payment under this Agreement, the Company shall be subrogated to the extent of such payment to all of the related rights of recovery of Indemnitee against other persons or entities (other than Indemnitee's successors), including any entity or enterprise referred to in clause (i) of the definition of "Indemnifiable Claim" in Section 1(g). Indemnitee shall execute all papers reasonably required to evidence such rights (all of Indemnitee's reasonable Expenses, including attorneys' fees and charges, related thereto to be reimbursed by or, at the option of Indemnitee, advanced by the Company).

14. No Duplication of Payments. The Company shall not be liable under this Agreement to make any payment to Indemnitee in respect of any Indemnifiable Losses to the extent Indemnitee has otherwise actually received and is entitled to retain payment (net of any Expenses incurred in connection therewith and any repayment by Indemnitee made with respect thereto) under any insurance policy, the Constituent Documents and Other Indemnity Provisions or otherwise (including from any entity or enterprise referred to in clause (i) of the definition of "Indemnifiable Claim" in Section 1(g)) in respect of such Indemnifiable Losses otherwise indemnifiable hereunder.

15. Defense of Claims. Except for any Indemnifiable Claim asserted by or in the right of the Company (as to which Indemnitee shall be entitled to exclusively control the defense), the Company shall be entitled to participate in the defense of any Indemnifiable Claim or to assume the defense thereof, with counsel reasonably satisfactory to Indemnitee. The Company's participation in the defense of any Indemnifiable Claim of which the Company has not assumed the defense will not in any manner affect the rights of Indemnitee under this Agreement, including Indemnitee's right to control the defense of suchIndemnifiable Claims. With respect to the period (if any) commencing at the time at which the Company notifies Indemnitee that the Company has assumed the defense of any Indemnifiable Claim and continuing for so long as the Company shall be using its reasonable best efforts to provide an effective defense of such Indemnifiable Claim, the Company shall have the right to control the defense of such

Indemnifiable Claim and shall have no obligation under this Agreement in respect of any attorneys' or experts' fees or expenses or any other costs or expenses paid or incurred by Indemnitee in connection with defending such Indemnifiable Claim (other than such costs and expenses paid or incurred by Indemnitee in connection with any cooperation in the Company's defense of such Indemnifiable Claim or other action undertaken by Indemnitee at the request of the Company or with the consent of the Company (which consent shall not be unreasonably withheld, conditioned or delayed)); *provided* that if Indemnitee believes, after consultation with counsel selected by Indemnitee, that (a) the use of counsel chosen by the Company to represent Indemnitee would present such counsel with an actual or potential conflict, (b) the named parties in any such Indemnifiable Claim (including any impleaded parties) include both the Company and Indemnitee and Indemnitee shall conclude that there may be one or more legal defenses available to him or her that are different from or in addition to those available to the Company, or (c) any such representation by such counsel would be precluded under the applicable standards of professional conduct then prevailing, then Indemnitee shall be entitled to retain and use the services of separate counsel (but not more than one law firm plus, if applicable, local counsel in respect of any particular Indemnifiable Claim) at the Company's expense. Nothing in this Agreement shall limit Indemnitee's right to retain or use his or her own counsel at his or her own expense in connection with any Indemnifiable Claim; *provided* that in all events Indemnitee shall not unreasonably interfere with the conduct of the defense by the Company of any Indemnifiable Claim that the Company shall have assumed and of which the Company shall be using its reasonable best efforts to provide an effective defense. The Company shall not be liable to Indemnitee under this Agreement for any amounts paid in settlement of any threatened or pending Indemnifiable Claim effected without the Company's prior written consent. The Company shall not, without the prior written consent of Indemnitee, effect any settlement of any threatened or pending Indemnifiable Claim to which Indemnitee is, or could have been, a party unless such settlement solely involves the payment of money and includes a complete and unconditional release of Indemnitee from all liability on any claims that are the subject matter of such Indemnifiable Claim. Neither the Company nor Indemnitee shall unreasonably withhold, condition or delay its consent to any proposed settlement; *provided* that Indemnitee may withhold consent to any settlement that does not provide a complete and unconditional release of Indemnitee.

16. Successors and Binding Agreement.

(a) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation, reorganization or otherwise) to all or substantially all of the business or assets of the Company, by agreement in form and substance satisfactory to Indemnitee and his or her counsel, expressly to assume and agree to perform this Agreement in the same manner and to the same extent the Company would be required to perform if no such succession had taken place. This Agreement shall be binding upon and inure to the benefit of the Company and any successor to the Company, including any person acquiring directly or indirectly all or substantially all of the business or assets of the Company whether by purchase, merger, consolidation, reorganization or otherwise (and such successor will thereafter be deemed the "***Company***" for purposes of this Agreement), but shall not otherwise be assignable or delegable by the Company.

(b) This Agreement shall inure to the benefit of and be enforceable by Indemnitee’s personal or legal representatives, executors, administrators, heirs, distributees, legatees and other successors.

(c) This Agreement is personal in nature and neither of the parties hereto shall, without the consent of the other, assign or delegate this Agreement or any rights or obligations hereunder except as expressly provided in Sections 16(a) and 16(b). Without limiting the generality or effect of the foregoing, Indemnitee’s right to receive payments hereunder shall not be assignable, whether by pledge, creation of a security interest or otherwise, other than by a transfer by Indemnitee’s will or by the laws of descent and distribution, and, in the event of any attempted assignment or transfer contrary to this Section 16(c), the Company shall have no liability to pay any amount so attempted to be assigned or transferred.

17. Notices. For all purposes of this Agreement, all communications, including notices, consents, requests or approvals, required or permitted to be given hereunder shall be in writing and shall be deemed to have been duly given when hand delivered or dispatched by electronic facsimile transmission (with receipt thereof orally confirmed), or five business days after having been mailed by United States registered or certified mail, return receipt requested, postage prepaid or one business day after having been sent for next-day delivery by a nationally recognized overnight courier service, addressed to the Company (to the attention of the Secretary of the Company) and to Indemnitee at the applicable address shown on the signature page hereto, or to such other address as any party hereto may have furnished to the other in writing and in accordance herewith, except that notices of changes of address will be effective only upon receipt.

18. Governing Law. The validity, interpretation, construction and performance of this Agreement shall be governed by and construed in accordance with the substantive laws of the State of Delaware, without giving effect to the principles of conflict of laws of such State. The Company and Indemnitee each hereby irrevocably consent to the jurisdiction of the Chancery Court of the State of Delaware for all purposes in connection with any action or proceeding which arises out of or relates to this Agreement and agree that any action instituted under this Agreement shall be brought only in the Chancery Court of the State of Delaware.

19. Validity. If any provision of this Agreement or the application of any provision hereof to any person or circumstance is held invalid, unenforceable or otherwise illegal, the remainder of this Agreement and the application of such provision to any other person or circumstance shall not be affected, and the provision so held to be invalid, unenforceable or otherwise illegal shall be reformed to the extent, and only to the extent, necessary to make it enforceable, valid or legal. In the event that any court or other adjudicative body shall decline to reform any provision of this Agreement held to be invalid, unenforceable or otherwise illegal as contemplated by the immediately preceding sentence, the parties thereto shall take all such action as may be necessary or appropriate to replace the provision so held to be invalid, unenforceable or otherwise illegal with one or more alternative provisions that effectuate the purpose and intent of the original provisions of this Agreement as fully as possible without being invalid, unenforceable or otherwise illegal. This Agreement shall replace and supersede the indemnification agreement in effect between Indemnitee and the Company immediately prior to the execution and delivery of this Agreement by Indemnitee and the Company (the “***Prior***

Indemnification Agreement”); *provided* that if, after giving effect to the foregoing provisions of this Section 19 and any actions contemplated thereby that are taken pursuant thereto, Indemnitee is not satisfied, in his or her sole discretion, with the rights and benefits provided to Indemnitee by this Agreement, Indemnitee may elect to have the Prior Indemnification Agreement, rather than this Agreement, govern the rights and obligations of the parties hereto in relation to the subject matter of the Prior Indemnification Agreement with the same force and effect as if this Agreement had never replaced or superseded the Prior Indemnification Agreement (it being the intent of the parties hereto to fully preserve the validity, binding effect and enforceability of the Prior Indemnification Agreement in that event).

20. Miscellaneous. No provision of this Agreement may be waived, modified or discharged unless such waiver, modification or discharge is agreed to in writing signed by Indemnitee and the Company. No waiver by either party hereto at any time of any breach by the other party hereto or compliance with any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. No agreements or representations, oral or otherwise, expressed or implied with respect to the subject matter hereof have been made by either party hereto that are not set forth expressly in this Agreement.

21. Legal Fees and Expenses; Interest.

(a) It is the intent of the Company that Indemnitee not be required to incur legal fees and or other Expenses associated with the interpretation, enforcement or defense of Indemnitee’s rights under this Agreement by litigation or otherwise because the cost and expense thereof would substantially detract from the benefits intended to be extended to Indemnitee hereunder. Accordingly, without limiting the generality or effect of any other provision hereof, if it should appear to Indemnitee that the Company has failed to comply with any of its obligations under this Agreement (including its obligations under Section 3) or in the event that the Company or any other person takes or threatens to take any action to declare this Agreement void or unenforceable, or institutes any litigation or other action or proceeding designed to deny, or to recover from, Indemnitee the benefits provided or intended to be provided to Indemnitee hereunder, the Company irrevocably authorizes Indemnitee from time to time to retain counsel of Indemnitee’s choice, at the expense of the Company as hereafter provided, to advise and represent Indemnitee in connection with any such interpretation, enforcement or defense, including the initiation or defense of any litigation or other legal action, whether by or against the Company or any director, officer, stockholder or other person affiliated with the Company, in any jurisdiction. Notwithstanding any existing or prior attorney-client relationship between the Company and such counsel, the Company irrevocably consents to Indemnitee’s entering into an attorney-client relationship with such counsel, and in that connection the Company and Indemnitee agree that a confidential relationship shall exist between Indemnitee and such counsel. The Company will pay and be solely financially responsible for any and all attorneys’ and related fees and expenses incurred by Indemnitee in connection with any of the foregoing to the fullest extent permitted or required by the laws of the State of Delaware in effect on the date hereof or as such laws may from time to time hereafter be amended to increase the scope of such permitted or required payment of such fees and expenses.

(b) Any amount due to Indemnitee under this Agreement that is not paid by the Company by the date on which it is due will accrue interest at the maximum legal rate under Delaware law from the date on which such amount is due to the date on which such amount is paid to Indemnitee.

22. Certain Interpretive Matters. Unless the context of this Agreement otherwise requires, (a) "it" or "its" or words of any gender include each other gender, (b) words using the singular or plural number also include the plural or singular number, respectively, (c) the terms "hereof," "herein," "hereby" and derivative or similar words refer to this entire Agreement, (d) the terms " "Section" or "Exhibit" refer to the specified Section or Exhibit of or to this Agreement, (e) the terms "include," "includes" and "including" will be deemed to be followed by the words "without limitation" (whether or not so expressed), and (f) the word "or" is disjunctive but not exclusive. Whenever this Agreement refers to a number of days, such number will refer to calendar days unless business days are specified and whenever action must be taken (including the giving of notice or the delivery of documents) under this Agreement during a certain period of time or by a particular date that ends or occurs on a non-business day, then such period or date will be extended until the immediately following business day. As used herein, "business day" means any day other than Saturday, Sunday or a United States federal holiday.

23. Counterparts. This Agreement may be executed in counterparts, each of which will be deemed to be an original but all of which together shall constitute one and the same agreement.

[Signatures Appear on Following Page]

IN WITNESS WHEREOF, Indemnitee has executed and the Company has caused its duly authorized representative to execute this Agreement as of the date first above written.

SILVERBOW RESOURCES, INC.
525 N. Dairy Ashford, Ste. 1200
Houston, TX 77079

By: ____

____

____

____

EXHIBIT A

UNDERTAKING

This Undertaking is submitted pursuant to the Director and Officer Indemnification Agreement, dated as of ___________________, 201_ (the "***Indemnification Agreement***"), between SilverBow Resources, Inc., a Delaware corporation (the "***Company***"), and the undersigned. Capitalized terms used and not otherwise defined herein have the meanings ascribed to such terms in the Indemnification Agreement.

The undersigned hereby requests **[payment], [advancement], [reimbursement]** by the Company of Expenses which the undersigned **[has incurred] [reasonably expects to incur]** in connection with _____________________ (the "***Indemnifiable Claim***").

The undersigned hereby undertakes to repay the **[payment]**, **[advancement]**, **[reimbursement]** of Expenses made by the Company to or on behalf of the undersigned in response to the foregoing request to the extent it is determined, following the final disposition of the Indemnifiable Claim and in accordance with Section 8 of the Indemnification Agreement, that the undersigned is not entitled to indemnification by the Company under the Indemnification Agreement with respect to the Indemnifiable Claim.

IN WITNESS WHEREOF, the undersigned has executed this Undertaking as of this _____ day of ______________, _____.

____
[Indemnitee]

(Back To Top)

Section 4: EX-21 (EXHIBIT 21)

Exhibit 21

SilverBow Resources, Inc. - Significant Subsidiaries

SilverBow Resources Operating, LLC

(Back To Top)

Section 5: EX-23.1 (EXHIBIT 23.1)

H.J. GRUY AND ASSOCIATES, INC.
6575 West Loop South, Suite 550, Bellaire, Texas 77401 TEL. (713) 739-1000 FAX (713) 739-6112

Exhibit 23.1

CONSENT OF H.J. GRUY AND ASSOCIATES, INC.

We hereby consent to the use of the name H.J. Gruy and Associates, Inc. and of reference to H.J. Gruy and Associates, Inc. and to the inclusion of and references to our report, or information contained therein, dated January 26, 2018, prepared for SilverBow Resources, Inc. in the SilverBow Resources, Inc. Annual Report on Form 10-K for the year ended December 31, 2017.

H.J. GRUY AND ASSOCIATES, INC.

By: /s/ Marilyn Wilson
Marilyn Wilson, P.E.
President and Chief Executive Officer

March 1, 2018
Houston, Texas

(Back To Top)

Section 6: EX-23.2 (EXHIBIT 23.2)

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

SilverBow Resources, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3/A (No. 333-216782) and Form S-8 (Nos. 333-218246, 333-210936 and 333-215235) of SilverBow Resources, Inc. of our reports dated March 1, 2018 relating to the 2017 and 2016 consolidated financial statements, and the effectiveness of SilverBow Resources, Inc.'s internal control over financial reporting as of December 31, 2017, which appear in this Annual Report on Form 10-K.

/s/ BDO USA, LLP

Houston Texas
March 1, 2018

(Back To Top)

Section 7: EX-23.3 (EXHIBIT 23.3)

Exhibit 23.3

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference on the following Registration Statements:

(1) Registration Statement (Form S-3/A No. 333-216782) of SilverBow Resources, Inc.
(2) Registration Statement (Form S-8 No. 333-210936) pertaining to the SilverBow Resources, Inc. 2016 Equity Incentive Plan
(3) Registration Statement (Form S-8 No. 333-218246) pertaining to the SilverBow Resources, Inc. 2016 Equity Incentive Plan
(4) Registration Statement (Form S-8 No. 333-215235) pertaining to the SilverBow Resources, Inc. Inducement Plan

of our report dated March 4, 2016, with respect to the consolidated financial statements of SilverBow Resources, Inc. (formerly named Swift Energy Company) and subsidiaries included in the Annual Report (Form 10-K) for the year ended December 31, 2015.

/s/ Ernst & Young LLP

Houston, Texas

March 1, 2018

(Back To Top)

Section 8: EX-31.1 (EXHIBIT 31.1)

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Sean C. Woolverton, certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ended December 31, 2017, of SilverBow Resources, Inc. (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018

/s/Sean C. Woolverton
Sean C. Woolverton
Chief Executive Officer

(Back To Top)

Section 9: EX-31.2 (EXHIBIT 31.2)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, G. Gleeson Van Riet, certify that:

1. I have reviewed this Annual Report on Form 10-K for the period ended December 31, 2017, of SilverBow Resources, Inc. (the "registrant");

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting, to be designed under our supervision, 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;
    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 1, 2018	/s/ G. Gleeson Van Riet
	G. Gleeson Van Riet Executive Vice President and Chief Financial Officer

(Back To Top)

Section 10: EX-32 (EXHIBIT 32)

Exhibit 32

Certification of Chief Executive Officer and Chief Financial Officer

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report on Form 10-K for the period ended December 31, 2017 of SilverBow Resources, Inc. (the “Company”) as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Sean C. Woolverton, the Chief Executive Officer of the Company, and G. Gleeson Van Riet, the Executive Vice President and Chief Financial Officer of the Company, each certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Swift.

Date: March 1, 2018	/s/ Sean C. Woolverton
	Sean C. Woolverton Chief Executive Officer

Date: March 1, 2018	/s/ G. Gleeson Van Riet
	G. Gleeson Van Riet Executive Financial President and Chief Financial Officer

(Back To Top)

Section 11: EX-99.1 (EXHIBIT 99.1)

H.J. GRUY AND ASSOCIATES, INC.
6575 West Loop South, Suite 550, Bellaire, Texas 77401 TEL. (713) 739-1000 FAX (713) 739-6112

Exhibit 99-1

January 26, 2018

SilverBow Resources
575 N. Dairy Ashford Road, Suite 1200
Houston, Texas 77079

Re: Year-End 2017
S.E.C. Guideline Reserves
Independent Estimation

Ladies and Gentlemen:

At your request, we have independently prepared an estimate of the oil, natural gas, and natural gas liquid proved reserves and future net cash flows effective December 31, 2017, attributable to SilverBow Resources (SilverBow) net interests in certain oil and gas properties. The estimated reserves are located in the Continental United States. Based on information provided by SilverBow, the estimated reserves reported herein comprise all of the SilverBow proved reserves.

This report, completed on January 26, 2018 has been prepared for SilverBow, and is provided for inclusion in relevant U.S. Securities and Exchange Commission registration statements or other Securities and Exchange Commission filings. All proved reserves are estimated in compliance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 210.4-10(a), and in our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The net reserves, future net cash flow, and discounted future net cash flow to the SilverBow interest in these properties, effective December 31, 2017, are estimated to be as follows:

Proved Reserves

	Estimated Net Reserves			Estimated Future Net Cash Flow	
	Oil (Barrels)	Gas (Mcf)	Natural Gas Liquids (Barrels)	Not Discounted	Discounted at 10 Percent Per Year

Proved Producing	4,865,173	372,091,939	8,050,637	$	898,445,093	$	470,752,668
Proved Nonproducing	161,225	5,412,830	380,950	$	14,129,113	$	6,367,990
Proved Undeveloped	2,133,297	465,230,305	14,689,769	$	924,542,197	$	334,616,313
Total Proved	7,159,695	842,735,074	23,121,356	$	1,837,116,403	$	811,736,971

*Note: Totals may not add due to rounding.

The discounted future net cash flows summarized in the above table is computed using a discount rate of 10 percent per annum. Future net cash flow as presented herein is defined as the future cash inflow attributable to the evaluated interest less, if applicable, future operating costs, ad valorem taxes, and future capital expenditures. Future cash inflow is defined as gross cash inflow less, if applicable, royalties and severance taxes. Future cash inflow and future net cash flow stated in this report exclude consideration of state and federal income tax. Future costs of facility and well abandonments, and the restoration of producing properties to satisfy environmental standards are not deducted from cash flow.

This reserve report conforms to the term third party reports as stated in Regulation S-K, Item 1202. The assumptions, data, methods, and procedures used by H.J. Gruy and Associates, Inc. to conduct the independent reserve estimates are appropriate for the purposes of this report, and we have used all methods and procedures we consider necessary under the circumstances to prepare this report. The proved reserves estimates are in compliance with the applicable definitions contained in Securities and Exchange Commission Regulation S-X.

The processes, methods, and procedures employed by us to evaluate the necessary information, estimate reserves, support assumptions, and document methodologies are effective, and meet or exceed guideline standards. We used appropriate engineering, geologic, and evaluation principles that are consistent with practices routinely recognized in the petroleum industry. Reserve estimates are based on extrapolation of established performance trends, material balance calculations, volumetric calculations, analogy with the performance of comparable wells, or a combination of these methods.

The primary economic assumptions in the reserves estimating process include the application of product prices, operating costs, and future capital expenditures that are not escalated and therefore remain constant for the projected life of each property. Product benchmark prices are based on an average of 2017 first-day-of-the-month prices in accordance with Regulation S-X guidelines. A price differential is applied to the oil, natural gas, and natural gas liquids benchmark prices to adjust for transportation, geographic property location, and quality or energy content. As a reference, the 12-month average benchmark price for oil is $51.19 per barrel, referenced to West Texas Intermediate (WTI) price at Cushing Oklahoma, and for natural gas is $3.03 per million British thermal units, referenced to Henry Hub gas price. The average adjusted prices, for oil, natural gas, and natural gas liquids, used to determine reserves are $50.38 per barrel, $2.95 per thousand standard cubic feet and $20.32 per barrel, respectively, over the projected lives of the assets.

Lease operating costs are based on historical operating expense records. For all properties, general and administrative overhead expenses have been included. Estimates of capital costs are included as required for workovers and development.

In conducting this work, we relied on data supplied by SilverBow. The extent and character of ownership, oil and natural gas sales prices, operating costs, future capital expenditures, historical production, accounting, geological, and engineering data were accepted as represented, and we have assumed the authenticity of all documents submitted. No independent well tests, property inspections, or audits of operating statements were conducted by our staff in conjunction with this work. We did not verify or determine the extent, character, status, or liability, if any, of production imbalances, hedging activities, or any current or possible future detrimental environmental site conditions. In our judgment, there are no instances where current local, state, or federal regulations will materially impact the ability of SilverBow to recover the estimated proved reserves.

In order to estimate the proved reserves and future cash flows attributable to SilverBow, we have relied on geological, engineering, and economic data furnished by our client. Although we instructed our client to provide all pertinent data, and we made a reasonable effort to analyze it carefully with methods applied in the petroleum industry, there is no guarantee that the volumes of hydrocarbons or the cash flows projected will be realized.

Hydrocarbon reserves estimates contain inherent uncertainties. The estimation of reserves is based on the application of a wide range of technologies and the subjective interpretation of currently available data; therefore, the reserves discussed herein are considered estimates only and should not be construed as exact quantities. Future economic or operating conditions may affect recovery of estimated reserves and cash flows, and reserves of all categories may be subject to change as more performance data become available or as alternative estimating methods become applicable. Estimates of future net cash flow and discounted future net cash flow should not be interpreted to represent the fair market value for the estimated reserves.

H.J. Gruy and Associates, Inc. is a privately owned, independent consultancy, and compensation for our efforts is not contingent upon the outcome of our work. H.J. Gruy and Associates, Inc. and its employees have no direct financial interest in SilverBow Resources, or the properties, nor do we contemplate any future direct financial interest. Any distribution or publication of this work or any part thereof must include this letter in its entirety.

Yours very truly,

H.J. GRUY AND ASSOCIATES, INC.
Texas Registration Number F-000637

/s/ Marilyn Wilson

Marilyn Wilson, P.E.
Texas License Number 59498 **[SEAL]**
President and Chief Operating Officer

MW:pab

CERTIFICATE OF QUALIFICATION

I, Marilyn Wilson, of 6575 West Loop South, Suite 550, Bellaire, Texas 77401, hereby certify:

1. I am President of H.J. Gruy and Associates, Inc, and I am the engineer responsible for the estimates of reserves, future production, and future income determined by H.J. Gruy and Associates, Inc. and preparation of the reserves report for Swift Energy Company effective December 31, 2017, and dated January 26, 2018, attached herewith.

2. I hold a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University, and I am a Licensed Professional Engineer in the State of Texas, License Number 59498. I am a member of the Society of Petroleum Engineers, and I am a past President and member of the Society of Petroleum Evaluation Engineers. I have over 30 years of experience in the evaluation of oil and gas reserves.

3. Based on my educational and professional background, I meet or exceed the professional qualifications as a Reserves Estimator presented in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers.

H.J. GRUY AND ASSOCIATES, INC.
Texas Registration Number F-000637

by: /s/ Marilyn Wilson
Marilyn Wilson, P.E.
President and Chief Operating Officer

(Back To Top)