UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 001-36550

PAR PACIFIC HOLDINGS, INC.
(Exact name of registrant as specified in its charter)

Delaware	**84-1060803**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
800 Gessner Road, Suite 875	
Houston, Texas	**77024**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (281) 899-4800

Securities registered under Section 12(b) of the Act:

Title of each class	Name of Exchange on which registered
Common stock, par value $0.01 per share	**The 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 Act. 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 (or for such shorter period that the registrant was required to file such reports), 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 (§ 229.405 of this chapter) 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 emerging growth company. See definitions 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	☐	(Do not check if a smaller reporting company)	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 Act). Yes ☐ No ☒

The aggregate market value of voting and non-voting common equity held by non-affiliates of the registrant was approximately $449,038,962 based on the closing sales price of the common stock on the NYSE MKT as of June 30, 2017 . As of March 7, 2018 , 46,327,234 shares of the registrant's Common Stock, $0.01 par value, were issued and outstanding.

Documents Incorporated By Reference

Certain information required to be disclosed in Part III of this report is incorporated by reference from the registrant's definitive proxy statement or an amendment to this report, which will be filed with the SEC not later than 120 days after the end of the fiscal year covered by this report.

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Glossary of Selected Industry Terms

Unless otherwise noted or indicated by context, the following terms used in this Annual Report on Form 10- K have the following meanings:

barrel or bbl	A common unit of measure in the oil industry, which equates to 42 gallons.
blendstocks	Various compounds that are combined with gasoline or diesel from the crude oil refining process to make finished gasoline and diesel; these may include natural gasoline, FCC unit gasoline, ethanol, reformate, or butane, among others.
Brent	A light, sweet North Sea crude oil, characterized by an API gravity of 38 degrees and a sulfur content of approximately 0.4% by weight that is used as a benchmark for other crude oils.
cardlock	Automated unattended fueling sites that are open all day and are designed for commercial fleet vehicles.
catalyst	A substance that alters, accelerates, or instigates chemical changes, but is not produced as a product of the refining process.
CO_2	Carbon dioxide.
condensate	Light hydrocarbons which are in gas form underground, but are a liquid at normal temperatures and pressure.
crack spread	A simplified calculation that measures the difference between the price for light products and crude oil. For example, we reference the 4-1-2-1 crack spread, which is a general industry standard that approximates the per barrel refining margin resulting from processing four barrels of crude oil to produce one barrel of gasoline, two barrels of distillate (jet fuel and diesel), and one barrel of fuel oil.
distillates	Refers primarily to diesel, heating oil, kerosene, and jet fuel.
ethanol	A clear, colorless, flammable oxygenated liquid. Ethanol is typically produced chemically from ethylene or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. It is used in the United States as a gasoline octane enhancer and oxygenate.
feedstocks	Crude oil or partially refined petroleum products that are processed or blended into refined products.
jobber	A petroleum marketer.
LSFO	Low sulfur fuel oil.
Mbbls	Thousand barrels of crude oil or other liquid hydrocarbons.
Mbpd	Thousand barrels per day.
MMcf	Million cubic feet of natural gas.
MMcfd	Million cubic feet per day.
MMcfe	Million cubic feet equivalent which is determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil.
MMbtu	Million British thermal units.
MW	Megawatt.
Nelson Complexity Index	A measure of the complexity of a given refinery compared to crude distillation, which is assigned a complexity factor of 1.0. The index number is an indication of an oil refinery's ability to process feedstocks, such as heavier and higher sulfur content crude oils, into value-added products. Generally, more complex refineries have higher index numbers.
NGL	Natural gas liquid.
NOx	Nitrogen oxides.
refined products	Petroleum products, such as gasoline, diesel, and jet fuel, that are produced by a refinery.
throughput	The volume processed through a unit or refinery.
turnaround	A periodically required standard procedure to inspect, refurbish, repair, and maintain a refinery. This process involves the shutdown and inspection of major processing units and typically occurs every three to five years.
single-point mooring	Also known as a single buoy mooring, refers to a loading buoy that is anchored offshore and serves as an interconnect for tankers loading or offloading crude oil and refined products.
SO_2	Sulfur dioxide.
WTI	West Texas Intermediate crude oil, a light, sweet crude oil, typically characterized by an API gravity between 38 degrees and 40 degrees and a sulfur content of approximately 0.3% by weight that is used as a benchmark for other crude oils.
yield	The percentage of refined products that is produced from crude oil and other feedstocks, net of fuel used as energy.

PART I

Item 1. BUSINESS

OVERVIEW

Par Pacific Holdings, Inc., based in Houston, Texas, owns, manages, and maintains interests in energy and infrastructure businesses. Our strategy is to identify, acquire, and operate energy and infrastructure companies with attractive competitive positions. We changed our name from Par Petroleum Corporation to Par Pacific Holdings, Inc. effective October 20, 2015.

Our business is organized into three primary operating segments:

1) **Refining** - Our refinery in Kapolei, Hawaii, produces ultra-low sulfur diesel ("ULSD"), gasoline, jet fuel, marine fuel, low sulfur fuel oil ("LSFO"), and other associated refined products primarily for consumption in Hawaii. Our refinery in Newcastle, Wyoming produces gasoline, ULSD, jet fuel, and other associated refined products that are primarily marketed in Wyoming and South Dakota.

2) **Retail** - Our retail outlets sell gasoline, diesel, and retail merchandise throughout the islands of Oahu, Maui, Hawaii, and Kauai. Our retail network includes Hele and "76" branded retail sites, company-operated convenience stores, 7-Eleven operated convenience stores, other sites operated by third parties, and unattended cardlock locations.

3) **Logistics** - We own and operate terminals, pipelines, a single-point mooring ("SPM"), and trucking operations to distribute refined products throughout the islands of Oahu, Maui, Hawaii, Molokai, and Kauai. In addition, we own and operate a crude oil pipeline gathering system, a refined products pipeline, storage facilities, and loading racks in Wyoming. We also own and operate a jet fuel storage facility and pipeline that serve Ellsworth Air Force Base in South Dakota.

We also own an equity investment in Laramie Energy, LLC (" Laramie Energy ," formerly known as Piceance Energy, LLC), a joint venture entity focused on producing natural gas in Garfield, Mesa, and Rio Blanco Counties, Colorado.

The refining, retail, and logistics segments were established through the acquisitions of Par Hawaii Refining, LLC ("PHR," formerly Hawaii Independent Energy, LLC) and Par Hawaii, Inc. (" PHI ," formerly Koko'oha Investments, Inc.), which owns 100% of the outstanding membership interests of Mid Pac Petroleum, LLC ("Mid Pac"). PHR was acquired from Andeavor (formerly Tesoro Corporation, "Tesoro") on September 25, 2013 for approximately $75 million in cash, plus net working capital and inventories, certain contingent earn-out payments of up to $40 million , and the funding of certain start-up expenses and overhaul costs prior to closing. PHI was acquired on April 1, 2015 for cash consideration of approximately $74.4 million and the assumption of $45.3 million of debt.

On July 14, 2016, we acquired all of the issued and outstanding units representing the membership interests in Hermes Consolidated, LLC (d/b/a Wyoming Refining Company) and indirectly Wyoming Refining Company 's wholly owned subsidiary, Wyoming Pipeline Company, LLC (collectively, " Wyoming Refining " or "WRC") (the " WRC Acquisition "). Wyoming Refining owns and operates an 18 thousand barrels per day refinery and related logistics assets in Newcastle, Wyoming . We paid $209.4 million , including a deposit of $5.0 million paid in June 2016, and assumed debt consisting of term loans of $58.0 million and revolving loans of $10.1 million . The results of operations of Wyoming Refining are included in our refining and logistics segments effective July 14, 2016.

On January 9, 2018, we entered into an Asset Purchase Agreement with CHS Inc. (the " CHS Acquisition Agreement "), to acquire (a) twenty-one (21) owned retail gasoline, convenience store facilities and (b) twelve (12) leased retail gasoline, convenience store facilities, all at various locations in Washington and Idaho (collectively, the " CHS Station Properties "). The CHS Station Properties operate under the "Cenex®" brand name. We agreed to purchase the CHS Station Properties for a purchase price of $70 million plus the value of certain inventory at closing (the " CHS Acquisition "). The closing of the CHS Acquisition is subject to certain customary closing conditions and is expected to close in the first quarter of 2018.

Our Corporate and Other reportable segment includes administrative costs, our Texadian operations, which focused on sourcing, marketing, transporting, and distributing crude oil and refined products in the U.S. and Canada, and several small non-operated oil and gas interests that were owned by our predecessor. Please read Note 19—Segment Information to our consolidated financial statements under Item 8 of this Form 10-K for detailed information on our operating results by segment.

Corporate Information

Our common stock is listed and trades on the NYSE under the ticker symbol “PARR.” Our principal executive office is located at 800 Gessner Road, Suite 875, Houston, Texas 77024 and our telephone number is (281) 899-4800. Throughout this Annual Report on Form 10-K, the terms “Par,” “the Company,” “we,” “our,” and “us” refer to Par Pacific Holdings, Inc. and its consolidated subsidiaries unless the context suggests otherwise.

Available Information

Our website address is www.parpacific.com. Information contained on our website is not part of this Annual Report on Form 10-K. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any other materials filed with (or furnished to) the U.S. Securities and Exchange Commission (“SEC”) by us are available on our website (under “Investors”) free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC’s website at *http://www.sec.gov* .

OPERATING SEGMENTS

Refining

Our refining segment buys and refines crude oil and other feedstocks into petroleum products (such as gasoline and distillates) at our Hawaii and Wyoming refineries.

Hawaii Refinery

Our Hawaii refinery is located in Kapolei, Hawaii, on the island of Oahu on approximately 130 fee-owned acres about 20 miles west of Honolulu and is rated at 94 thousand barrels per day throughput capacity with a Nelson Complexity Index of 5.0. The Hawaii refinery's major processing units include crude distillation, vacuum distillation, visbreaking, hydrocracking, naphtha hydrotreating, and reforming units, which produce ULSD, gasoline, jet fuel, marine fuel, LSFO, and other associated refined products. We believe the configuration of our Hawaii refinery uniquely fits the demands of the Hawaii market.

We source our crude oil for the Hawaii refinery from North America, Asia, Latin America, Africa, the Middle East, and other sources. Crude oil is transported to Hawaii in tankers then discharged through our SPM. Our three underwater pipelines from the SPM allow crude oil and refined products to be transferred to and from the Hawaii refinery.

Crude oil is received into the Hawaii refinery tank farm, which includes 2.4 million barrels of total crude oil storage. We process the crude oil through various refining units into products and store them in the Hawaii refinery’s 2.5 million barrels of refined product tankage. The Hawaii refinery storage capacity allows us to manage the various product requirements of our customers in the state of Hawaii.

We finance our Hawaii refinery hydrocarbon inventories through our Supply and Offtake Agreements with J. Aron & Company LLC (“J. Aron”). Under the Supply and Offtake Agreements, J. Aron holds title to all crude oil and refined product stored in tankage at the Hawaii refinery. We purchase crude oil from J. Aron on a daily basis at market prices and sell refined products to J. Aron as they are produced. We repurchase these refined products from J. Aron prior to selling them to third parties.

Set forth below are summaries of the capacity of our Hawaii refinery:

Hawaii Refining Unit	Capacity (Mbpd)
Crude Unit	94
Vacuum Distillation Unit	40
Hydrocracker	19
Catalytic Reformer	13
Visbreaker	11
Naphtha Hydrotreater	13

Hawaii Refining Unit	Capacity
Hydrogen Plant (MMcfd)	18
Co-generation Turbine Unit (MW)	20

The Hawaii refinery operated at an average throughput of 73.7 thousand barrels per day, or 78% utilization, for the year ended December 31, 2017 . Below is a summary of our Hawaii refinery's throughput percentage by type of crude oil and the product yield percentage for the years ended December 31, 2017 , 2016 , and 2015 :

	Year Ended December 31,		
	2017	2016	2015
Feedstocks throughput (Mbpd)	73.7	70.2	77.3
Source of crude oil:			
North America	23.8%	41.7%	47.7%
Asia	23.1%	30.0%	33.0%
Africa	24.9%	13.7%	8.3%
Latin America	0.1%	3.9%	8.0%
Middle East	28.1%	10.7%	2.1%
Europe	—%	—%	0.9%
Total	100.0%	100.0%	100.0%
Yield (% of total throughput):			
Gasoline and gasoline blendstocks	27.8%	26.8%	26.2%
Distillates	48.2%	44.7%	44.1%
Fuel oils	15.7%	20.1%	22.0%
Other products	5.0%	4.8%	4.7%
Total yield	96.7%	96.4%	97.0%

Our Hawaii refining business sells refined products through our logistics network to wholesale and bulk customers and to our retail business in Hawaii. Wholesale customers include jobbers and other non-end users, as well as 36 fueling stations where operations and consumer pricing are controlled by third parties. Bulk customers include utilities, military bases, marine vessels, industrial end-users, and exports.

The profitability of our Hawaii refining business is heavily influenced by crack spreads in both the Singapore and U.S. West Coast markets. These markets reflect the closest, liquid market alternatives to source refined products for Hawaii. We believe the Singapore and Mid Pacific crack spreads (or four barrels of Brent crude oil converted into one barrel of gasoline, two barrels of distillate (diesel and jet fuel) and one barrel of fuel oil) best reflect a market indicator for our Hawaii operations. The Mid Pacific crack spread is calculated using a ratio of 80% Singapore and 20% San Francisco indexes. During the course of 2017 , both indexes exhibited significant volatility with lows reached during the late fourth quarter. The Singapore 4-1-2-1 crack spread averaged $7.18 per barrel during 2017 with a low of $4.62 per barrel in the fourth quarter and a high of $10.61 per barrel in the third quarter. The

Mid Pacific 4-1-2-1 crack spread averaged $8.45 per barrel during 2017 with a low of $5.80 per barrel in the fourth quarter and a high of $12.66 per barrel in the third quarter.

Below is a summary of average crack spreads for the years ended December 31, 2017 , 2016 , and 2015 :

	Year Ended December 31,		
	2017	2016	2015
4-1-2-1 Mid Pacific Crack Spread (1)	$ 8.45	$ 4.96	$ 8.31
4-1-2-1 Singapore Crack Spread	7.18	3.74	6.88

(1) Calculated using a ratio of 80% Singapore and 20% San Francisco indexes.

During a declining crude oil market, we tend to benefit from expanding crack spreads as our product portfolio pricing terms tend to lag our crude oil pricing terms ("pricing lag effect"). A significant portion of our contracts typically price at least one week in arrears and some of our utility customer contracts have at least a one month lag in the pricing terms. We economically hedge the pricing lag effect.

Wyoming Refinery

Our Wyoming refinery is located in Newcastle, Wyoming, on approximately 121 fee-owned acres, and is rated at 18 thousand barrels per day throughput capacity with a Nelson Complexity Index of 10.7. The Wyoming refinery's major processing units include crude distillation, catalytic cracker, naphtha hydrotreating, and reforming units, which produce gasoline, ULSD, jet fuel, and other associated refined products.

We source our crude oil for the Wyoming refinery from local producers as well as other North America sources. Most of the crude oil is delivered to the refinery via our owned pipeline and the rest is delivered by truck.

Crude oil is received into the refinery tank farm and crude oil terminals, which include 256 thousand barrels of total crude oil storage. We process the crude oil through various refining units into products and store them in the Wyoming refinery's 451 thousand barrels of refined product tankage. The Wyoming refinery storage capacity allows us to manage the various product requirements of our customers in the states of Wyoming and South Dakota and other targeted market destinations.

Set forth below is a summary of the capacity of our Wyoming refinery:

Wyoming Refining Unit	Capacity (Mbpd)
Crude Unit	18
Residual Fluid Catalytic Cracker	7
Catalytic Reformer	3
Naphtha Hydrotreater	3
Diesel Hydrotreater	5
Isomerization	5

The Wyoming refinery operated at an average throughput of 15.5 thousand barrels per day, or 86% utilization, for the year ended December 31, 2017 . Below is a summary of the Wyoming refinery's product yield percentage for the year ended December 31, 2017 and for the period from July 14, 2016 (the date of acquisition) to December 31, 2016:

	Year Ended December 31, 2017	**July 14, 2016 to December 31, 2016**
Feedstocks Throughput (Mbpd)	15.5	15.8
Yield (% of total throughput):		
Gasoline and gasoline blendstocks	51.9%	56.0%
Distillate	42.8%	39.3%
Fuel oil	2.2%	1.9%
Other products	0.8%	1.0%
Total yield	97.7%	98.2%

Our Wyoming refining business sells refined products through our logistics network to wholesale, bulk, and retail customers primarily in the Rapid City, South Dakota, area. Products are also distributed by rail from our refinery to longer-distance markets.

The profitability of our Wyoming refinery is heavily influenced by crack spreads in nearby markets. We believe our Wyoming refining operations are best captured by the Wyoming 3-2-1 Index, or three barrels of WTI converted into two barrels of gasoline and one barrel of distillate (jet fuel and diesel). We believe the Wyoming 3-2-1 crack spread, a 50%/50% blend of Rapid City 3-2-1 and Denver 3-2-1 (WTI based) crack spreads, best reflects a market indicator for our Wyoming refining and fuel distribution operations. The Wyoming 3-2-1 Index averaged $21.80 per barrel during 2017 with a low of $12.62 per barrel in the first quarter and a high of $34.29 per barrel in the third quarter. The Wyoming 3-2-1 Index averaged $16.27 per barrel during the period from July 14, 2016 to December 31, 2016.

Competition

All facets of the energy industry are highly competitive. Our competitors include major integrated, national, and independent energy companies. Many of these competitors have greater financial and technical resources and staff which may allow them to better withstand and react to changing and adverse market conditions.

Our refining business sources and obtains all of our crude oil from third-party sources and competes globally for crude oil and feedstocks. Our Hawaii refinery, through our facility with J. Aron, has access to a large variety of markets for crude oil imports and product exports. Please read “ Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations — Commitments and Contingencies — Supply and Offtake Agreements ” of this Form 10-K for further information. Our Wyoming refinery sources its crude oil and feedstocks primarily from the Petroleum Administration for Defense District IV Rocky Mountain (“PADD IV”) region of the United States.

Our refined product sales from our Hawaii refinery, outside the Hawaii market, typically target the Eastern Asia and U.S. West Coast markets. Our Wyoming refinery primarily sells refined products locally in the PADD IV region.

Retail

The retail segment includes 91 locations in Hawaii where we set the price to the retail consumer. Of these 91 locations, 37 are outlets operated by our personnel and include various sizes of kiosks, snack shops, or convenience stores. The remaining 54 locations, of which we own 20, are cardlock s or sites operated by third parties where we retain ownership of the fuel and set retail pricing.

We hold exclusive licenses within the state of Hawaii to utilize the “76” brand for retail locations. In 2017 and 2016, we completed the rebranding of 39 out of 91 fueling stations in Hawaii to Hele, a new proprietary brand. All of the manned locations and one cardlock are currently operated under one of those brands (see chart below). The “76” license agreement expires September 24, 2024, unless extended by mutual agreement.

The following table shows our owned and leased retail outlets by location and type:

Location and Channel of Trade	"76" Brand	Hele Brand	Unbranded	Total
Oahu				
Company operated	2	18	—	20
7-Eleven alliance	22	7	—	29
Fee operated	5	3	—	8
Cardlock	—	1	3	4
Oahu total	29	29	3	61
Big Island				
Company operated	3	6	—	9
Fee operated	3	—	—	3
Big Island total	6	6	—	12
Maui				
Company operated	1	4	—	5
Fee operated	2	—	—	2
Maui total	3	4	—	7
Kauai				
Company operated	3	—	—	3
Cardlock	—	—	8	8
Kauai total	3	—	8	11
Total for all locations	41	39	11	91

Competition

Competitive factors that affect our retail performance include product price, station appearance, location, customer service, and brand awareness. Our competitors include the Chevron, Shell, Texaco, Costco, Safeway, and Sam's Club national brands, a regional brand Aloha, and other local retailers.

Logistics

Our logistics segment generates revenues by charging fees for transporting crude oil to our refineries, delivering refined products to wholesale and bulk customers and to our retail business, and storing crude oil and refined products. Substantially all of our revenues from our logistics segment represent intercompany transactions that are eliminated in consolidation.

Hawaii Logistics

Our logistics network extends throughout the state of Hawaii. On Oahu, the system begins with our SPM located 1.7 miles offshore of our Hawaii refinery. This SPM allows for the safe, reliable, and efficient receipt of crude oil shipments to the Hawaii refinery, as well as both the receipt and export of finished products. Connecting the SPM to the Hawaii refinery are three undersea pipelines: a 30-inch line for crude oil, a 20-inch line, and a 16-inch line, both for the import or export of refined products. From the Hawaii refinery gate, we distribute refined products through our logistics network throughout the islands of Oahu, Maui, Hawaii, Molokai, and Kauai and for export to the U.S. West Coast and Asia.

The Oahu logistics network includes a 27-mile wholly owned and operated pipeline network that transports refined products from our Hawaii refinery to delivery locations (the "Honolulu Products Pipeline"). The majority of our Oahu refined product volumes are distributed through the Honolulu Products Pipeline to (i) our leased and operated Sand Island terminal, (ii) the Honolulu International Airport, (iii) interconnections to Navy and Air Force fuel facilities, and (iv) a third-party terminal in Honolulu Harbor. In addition to the Honolulu Products Pipeline, we own four proprietary pipelines connecting our Hawaii refinery to Kalaeloa Barbers Point Harbor, approximately three miles from the Hawaii refinery. The four pipelines deliver refined products to barges for distribution to the neighboring islands or export, as well as interconnecting with the other local Hawaii refinery, the local utility pipeline and storage network, and another third-party terminal on the west side of Oahu. The Oahu pipeline network is generally configured to be bidirectional, allowing for both delivery and receipt of products.

Our terminal facilities on Oahu include our Sand Island facility that comprises two tanks with a total capacity of 30 thousand barrels, as well as contractual rights to utilize strategically located third-party facilities both near the Hawaii refinery and at Honolulu Harbor near downtown.

We also operate a proprietary trucking business on Oahu to distribute gasoline and road diesel to the final point of sale.

Our logistics network for the islands neighboring Oahu consists of leased barge equipment and refined product tankage and proprietary trucking operations on the islands of Maui, Hawaii, Molokai, and Kauai. Specifically, we charter two barges to serve our neighbor island markets. This includes the Nale with 86 thousand barrels of capacity and the Ne'ena with 52 thousand barrels of capacity. In addition to neighbor island deliveries, the Ne'ena is utilized to service our bunker fuel customers, such as passenger cruise ships and container vessels. We also lease the barge Capella primarily for the import of ethanol from the U.S. West Coast with periodic backhauls of refined products for sale in the Pacific Northwest.

The barges deliver to and product is dispensed from a neighbor island network of seven petroleum terminals with total capacity of 301 thousand barrels.

Wyoming Logistics

Our Wyoming logistics network includes a 140-mile crude oil pipeline gathering system that provides us access to crude oil from the Powder River Basin. This network also includes a 40-mile refined products pipeline that transports product from our Wyoming refinery to a common carrier with access to Rapid City, South Dakota.

The logistics network in Wyoming includes storage, loading racks, and a rail siding at the refinery site. Our crude oil and refined product tanks at the Wyoming refinery have a total capacity of 470 thousand barrels. We also own and operate a jet fuel storage facility and pipeline that serve Ellsworth Air Force Base in South Dakota.

Hawaii Market

The Hawaii economy continues to grow. The Hawaii State Department of Business, Economic Development, and Tourism ("DBEDT") reported a projected population increase of 1.3% from 2016 to 2018. Real personal income is projected by DBEDT to grow by 1.5% in 2018. The number of visitors is projected to increase by 7.0% from 2016 to 2018 and continued growth is forecasted.

Demand for jet fuel is somewhat higher in Hawaii during the winter months than during the summer months as tourism increases during the winter months. Refining margins remain volatile and our results of operations may not reflect these historical seasonal trends.

Wyoming and South Dakota Markets

The primary market for our Wyoming refined products is the Pennington County, South Dakota, area which includes Rapid City. According to the U.S. Census Bureau, the population in Pennington County increased by 8.4% from 2010 to 2016. Demand for gasoline is highly seasonal, with a large increase in demand during the summer driving season. The local economy is anchored by tourism, including visitors to Mount Rushmore and the Black Hills, as well as government and healthcare spending. We also distribute refined products to customers in central and northeastern Wyoming. The economy in Wyoming is sensitive to demand for Powder River Basin coal and other locally-produced commodities.

OTHER OPERATIONS

Laramie Energy

We own an equity investment in Laramie Energy as a result of the contribution of certain natural gas and oil interests to a partnership with Laramie Energy II, LLC ("Laramie") in conjunction with our corporate reorganization in August 2012 and cash contributions made in 2015 and 2016.

Laramie Energy 's operations and assets are located in Garfield, Mesa, and Rio Blanco Counties, Colorado. On March 1, 2016 , Laramie Energy acquired certain properties in the Piceance Basin for $152.1 million . The acquired properties consisted of approximately 249 billion cubic feet equivalent of proved developed producing reserves as of December 31, 2016, more than 53,000 net operated acres, and more than 18,000 net non-operated acres. The acquired and existing properties produce primarily from the Mesaverde Formation and, to a lesser extent, the Mancos Formation. The majority of the acquired acreage is adjacent to Laramie Energy's existing assets.

As of December 31, 2017 , the estimated proved reserves we own indirectly through Laramie Energy are the following:

	Gas (MMcf)	Oil (Mbbls)	NGLs (Mbbls)	Total (MMcfe) (1)
Company's share of Laramie Energy:				
Proved developed	174,464	658	4,589	205,946
Proved undeveloped	118,578	449	2,913	138,750
Total	293,042	1,107	7,502	344,696

(1) MMcfe is computed using a ratio of 6 Mcf of natural gas to 1 barrel of oil or NGL.

For more information regarding our proved undeveloped reserves, please read " Item 2. — Properties — Reserves — Proved Undeveloped Reserves" of this Form 10-K.

The following table presents the estimated future net cash flows related to proved developed producing, proved developed non-producing, and proved undeveloped reserves that we own indirectly through Laramie Energy as of December 31, 2017 (in thousands):

	Proved Developed Producing	Proved Developed Non-producing	Proved Undeveloped	Total (1)
Estimated future undiscounted net cash flows	$ 263,587	$ —	$ 161,422	$ 425,009
Standardized measure of discounted future net cash flows	158,000	—	57,821	215,821

(1) Prices are based on the historical first-day-of-the-month twelve-month average posted price depending on the area. These prices are adjusted for quality, energy content, regional price differentials, and transportation fees. All prices are held constant throughout the lives of the properties. The average adjusted prices are $46.06 per barrel of crude oil, $20.97 per barrel of natural gas liquids, and $2.79 per Mcf of natural gas.

Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues calculated based on our estimated proved reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. This measure should not be considered a substitute for, or superior to, measures prepared in accordance with U.S. generally accepted accounting principles ("GAAP") . We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our natural gas and oil properties to other companies and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 at December 31, 2017 (in thousands):

	Company's Share of Laramie Energy
Standardized measure of discounted future net cash flows	$ 215,821
Present value of future income taxes discounted at 10% (1)	—
PV-10	$ 215,821

(1) There is no present value of future income taxes as we believe we have sufficient net operating loss carryforwards to offset any income. Please read Note 18— Income Taxes to our consolidated financial statements under Item 8 of this Form 10-K for further information.

For more information on our natural gas and oil operations, please read " Item 2. — Properties " of this Form 10-K.

Other non-operated oil and gas interests

We own other non-operated positions in producing and non-producing natural gas and oil interests and undeveloped leasehold interests and related assets in Colorado and New Mexico. As of December 31, 2017 , our estimated proved reserves related to other non-operated natural gas and oil interests of 500 MMcfe represented less than 1% of our total proved reserves owned indirectly through Laramie Energy of 344,696 MMcfe . Please read Note 23—Supplemental Oil and Gas Disclosures (Unaudited) to our consolidated financial statements under Item 8 of this Form 10-K for further information on our proved reserves related to other non-operated natural gas and oil interests.

Through our non-operated working interests, we have natural gas and oil leases with governmental entities and other third parties who enter into natural gas and oil leases or assignments with us in the regular course of our business.

Competition

The natural gas and oil business is highly competitive. The principal markets for natural gas and oil are refineries and transmission companies that have facilities near Laramie Energy's producing properties. Natural gas and oil produced from Laramie Energy's wells are normally sold to various purchasers. Natural gas wells are connected to pipelines generally owned by the natural gas purchasers. A variety of pipeline transportation charges are usually included in the calculation of the price paid for the natural gas. Crude oil is picked up and transported by the purchaser from the wellhead. In some instances, Laramie Energy is charged a fee for the cost of transporting the crude oil, which is deducted from or accounted for in the price paid for the crude oil.

BANKRUPTCY AND PLAN OF REORGANIZATION

Background and Plan Approval

In 2011 and 2012, our predecessor, Delta Petroleum Corporation ("Delta") and its subsidiaries (collectively "Debtors") filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware ("Bankruptcy Court"). In March 2012, the Debtors obtained approval from the Bankruptcy Court to proceed with Laramie as the sponsor of a plan of reorganization ("Plan"). In June 2012, Delta entered into a contribution agreement with a new joint venture formed by Delta, Laramie, and Laramie Energy to effect the transactions contemplated by the Plan. On August 31, 2012 ("Emergence Date"), Delta emerged from bankruptcy, amended and restated its certificate of incorporation and bylaws, changed its name to Par Petroleum Corporation, and contributed the majority of its natural gas and oil properties to Laramie Energy. The reorganization converted approximately $265 million of unsecured debt to equity and allowed us to preserve significant tax attributes.

General Recovery Trust

On the Emergence Date, the Delta Petroleum General Recovery Trust ("General Trust") was formed to pursue certain litigation against third parties or causes of action under the U.S. Bankruptcy Code and other claims and potential claims that the Debtors hold against third parties. The General Trust was funded with $1.0 million pursuant to the Plan.

The General Trust is pursuing all bankruptcy causes of action, claim objections, and resolutions and is responsible for winding up the bankruptcy. The General Trust is overseen by a three-person General Trust Oversight Board and our General Counsel is currently the trustee ("Recovery Trustee"). Costs, expenses, and obligations incurred by the General Trust are charged against assets of the General Trust. To conduct its operations and fulfill its responsibilities under the Plan and the trust agreements, the Recovery Trustee may request additional funding from us. Any litigation pending at the time we emerged from Chapter 11 was transferred to the General Trust for resolution and settlement in accordance with the Plan and the order confirming the Plan. We are the beneficiary of the General Trust, subject to the terms of the trust agreement and the Plan. Since the Emergence Date, the General Trust has filed various claims and causes of action against third parties before the Bankruptcy Court, which actions are ongoing. Upon liquidation of the various claims and causes of action held by the General Trust, the proceeds, less certain administrative reserves and expenses, will be transferred to us. It is unknown at this time what proceeds, if any, we will realize from the General Trust's litigation efforts.

Through December 31, 2013, the General Trust released approximately $5.2 million to us, which was available for our general use, due to a negotiated reduction in certain fees and claims associated with the bankruptcy, as well as a favorable variance in actual expenses versus budgeted expenses. No funds were released during the years ended December 31, 2017 , 2016 , 2015 , and 2014.

Shares Reserved for Unsecured Claims

The Plan provides that certain allowed general unsecured claims be paid with shares of our common stock. Pursuant to the Plan, allowed claims are settled at a ratio of 54.4 shares per $1,000 of claim. On the Emergence Date, 112 claims totaling approximately $73.7 million had been filed in the bankruptcy. Pursuant to the Plan, between the Emergence Date and December 31, 2013, the Recovery Trustee settled 84 claims with an aggregate face amount of $33.5 million for approximately $5.7 million in cash and 228,735 shares of common stock. Pursuant to the Plan, during the year ended December 31, 2014, the Recovery Trustee settled one additional claim with an aggregate face amount of $3.7 million for approximately 146 thousand shares of common stock. Pursuant to the Plan, during the year ended December 31, 2015, the Recovery Trustee settled one additional claim with an aggregate face amount of approximately $31 thousand for 1,674 shares of common stock. Pursuant to the Plan, during the year ended December 31, 2016, the Recovery Trustee settled six additional claims for aggregate consideration of approximately $0.7 million. No claims were settled pursuant to the Plan during the year ended December 31, 2017.

As of December 31, 2017 , two related claims totaling approximately $22.4 million remained to be resolved by the Recovery Trustee. One of the two remaining claims was filed by the U.S. Government for approximately $22.4 million relating to ongoing litigation concerning a plugging and abandonment obligation in Pacific Outer Continental Shelf Lease OCS-P 0320, comprising part of the Sword Unit in the Santa Barbara Channel, California. The second unliquidated claim, which is related to the same plugging and abandonment obligation, was filed by Noble Energy Inc., the operator and majority interest owner of the Sword Unit. We believe the probability of issuing stock to satisfy the full claim amount is remote, as the obligations upon which such proof of claim is asserted are joint and several among all working interest owners and Delta, our predecessor, only owned an approximate 3.4% aggregate working interest in the unit.

The settlement of claims is subject to ongoing litigation and we are unable to predict with certainty how many shares will be required to satisfy all claims. We have accrued approximately $0.5 million representing the estimated value of claims remaining to be settled which are deemed probable and estimable at December 31, 2017 . Please read “Item 7. – Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Commitments and Contingencies – Bankruptcy Matters” of this Form 10-K for further information.

Closing of the Bankruptcy Cases

On February 27, 2018, the Bankruptcy Court entered its final decree closing the Chapter 11 bankruptcy cases of Delta and the other Debtors, discharging the Recovery Trustee, and finding that all assets of the General Trust were resolved, abandoned, or liquidated and have been distributed in accordance with the requirements of the Plan. In addition, the final decree required the Company or the General Trust, as applicable, to maintain the current reserves owed on account of the remaining claims of the U.S. Government and Noble Energy, Inc.

ENVIRONMENTAL REGULATIONS

General

Our activities are subject to existing federal, state, and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing federal, state, and local laws, regulations, and rules regulating the release of materials in the environment or otherwise relating to the protection of human health, safety, and the environment will not have a material effect upon our capital expenditures, earnings, or competitive position with respect to our existing assets and operations. We cannot predict what effect additional regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons, and the environment resulting from our operations could have on our activities.

Periodically, we receive communications from various federal, state, and local governmental authorities asserting violations of environmental laws and/or regulations. These governmental entities may also propose or assess fines or require corrective actions for these asserted violations. We intend to respond in a timely manner to all such communications and to take appropriate corrective action. We do not anticipate that any such matters currently asserted will have a material impact on our financial condition, results of operations, or cash flows.

Refining activities

Like other petroleum refiners, our operations are subject to extensive and periodically changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Many of these regulations are becoming increasingly stringent and the cost of compliance can be expected to increase over time.

Our policy is to accrue environmental and clean-up related costs of a non-capital nature when it is probable that a liability has been incurred and the amount can be reasonably estimated. Such estimates may be subject to revision in the future as regulations and other conditions change.

Natural gas and oil production

Our activities with respect to exploration and production of natural gas and oil, including the drilling of wells and the operation and construction of pipelines, plants, and other facilities for extracting, transporting, processing, treating, or storing natural gas, crude oil, and other petroleum products, are subject to stringent environmental regulation by state and federal authorities, including the U.S. Environmental Protection Agency ("EPA"). Such regulation can increase the costs of planning, designing, installing, and operating such facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities are inherent in natural gas and oil production, transport, and storage operations and there can be no assurance that significant costs and liabilities will not be incurred. Moreover it is possible that other developments, such as spills or other unanticipated releases, stricter environmental laws and regulations and claims for damages to property or persons resulting from oil and gas production, transport, or storage would result in substantial costs and liabilities to us.

Climate Change and Regulation of Greenhouse Gases

According to certain scientific studies, emissions of CO_2, methane, nitrous oxide, and other gases commonly known as greenhouse gases ("GHGs") may be contributing to global warming of the earth's atmosphere and to global climate change. In response to the scientific studies, legislative and regulatory initiatives have been underway to limit GHG emissions. The U.S. Supreme Court determined that GHG emissions fall within the federal Clean Air Act ("CAA") definition of an "air pollutant". In response, the EPA promulgated an endangerment finding, paving the way for regulation of GHG emissions under the CAA. The EPA has now begun regulating GHG under the CAA. New construction or material expansions that meet certain GHG emissions thresholds will likely require that, among other things, a GHG permit be issued in accordance with the CAA regulations and we will be required in connection with such permitting to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce GHG emissions. As currently written and based on current company operations, however, our natural gas and oil exploration and production activities and our existing refining activities are not subject to federal GHG permitting requirements.

Furthermore, the EPA is currently developing refinery-specific GHG regulations and performance standards that are expected to impose GHG emission limits and/or technology requirements. These control requirements may affect a wide range of refinery operations. Any such controls could result in material increased compliance costs, additional operating restrictions for our business, and an increase in cost of the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity. We believe the change of Administration, however, makes it unlikely that such additional GHG requirements will be finalized in the near term.

The EPA has also promulgated rules requiring large sources to report their GHG emissions. Reports are being made in connection with our refining business. Sources subject to these reporting requirements also include on and offshore petroleum and natural gas production and onshore natural gas processing and distribution facilities that emit 25,000 metric tons or more of CO_2 equivalent per year in aggregate emissions from all site sources. To date, our natural gas and oil exploration and production activities are not subject to GHG reporting requirements.

In 2007, the state of Hawaii passed Act 234, which required that GHG emissions be rolled back on a statewide basis to 1990 levels by the year 2020. Although delayed, the Hawaii Department of Health ("DOH") has issued regulations that would require each major facility to reduce CO_2 emissions by 16% by 2020 relative to a calendar year 2010 baseline (the first year in which GHG emissions were reported to the EPA under 40 CFR Part 98). The final version of the state's GHG rules included an alternative for facilities to demonstrate that further GHG reductions are not economically viable and an additional provision that authorized the DOH to issue a waiver if GHGs are being effectively controlled as a consequence of other state initiatives and regulations such as the Renewable Portfolio Standard. The Hawaii refinery's capacity to further reduce fuel use and GHG emissions is limited. Since Hawaii's GHG emissions have already been reduced below 2010 levels and are projected to be less than the 1990 levels by 2020, we anticipate the Hawaii refinery will be able to demonstrate that no further reductions are required to meet the statewide goal. Any reductions imposed by the 16% facility-specific mandate would not be cost-effective and therefore should not be required. Additionally, the regulation allows for "partnering" with other facilities (principally power plants) which have already dramatically reduced greenhouse emissions or are on schedule to reduce CO_2 emissions in order to comply with the state's Renewable Portfolio Standards.

Regulation of GHG emissions is new and highly controversial. Further regulatory, legislative, and judicial developments are likely to occur in the future. Such developments may affect how these GHG initiatives will impact us. They may also impact the use of and demand for petroleum products, which could impact our business. Further, apart from these developments, tort claims alleging property damage against GHG emissions sources may be asserted. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on us.

National Ambient Air Quality Standards

Over the past several years the EPA has adopted a number of new and more stringent National Ambient Air Quality Standards ("NAAQS"). Specifically new NO_X and SO_2 standards were set in 2010 and a new particulate matter standard was set in 2012. States are required to develop State Implementation Plans and ultimately local air districts are required to adopt rules that will (over time) improve the air quality so that it will be "In Attainment" with the existing and new NAAQS. More stringent air pollutant standards and corresponding rules have already impacted and will continue to cause many refineries to invest heavily in additional air pollution controls. Thus far, Hawaii air quality, particularly on Oahu where our Hawaii refinery is located, has met even the most recent NAAQS and the Hawaii refinery itself has not been required to install new controls as result of local rules. Even so, NAAQS could and to a degree have already forced some changes for our customer base. Power plants on the Big Island, where SO_2 levels are already elevated due to volcanic activity, are switching from LSFO to diesel fuel. On Oahu, the state's largest utility frequently cites compliance with NAAQS as one of its justifications for moving towards a cleaner bridge fuel, potentially diesel or Liquefied Natural Gas before reaching its renewable goals. On October 1, 2015, the EPA adopted rules that would substantially tighten the NAAQS for ground-level ozone. This rule will cause many areas of the country to fall out of attainment and for the affected states to require additional controls and limits on combustion emissions and emissions of volatile organic compounds. We do not currently anticipate that the more stringent NAAQS will impact our Hawaii or Wyoming operations.

Regulation of Industrial Customer Base through Mercury Air Toxics Standard

Additional federal regulation of Hawaii-based power plants will likely have an impact on our Hawaii refinery because a portion of its production capacity and product mix has historically been dedicated to supplying industrial fuel oil for the islands' public utilities. On February 16, 2012, the EPA published National Emission Standards for Hazardous Air Pollutants ("NESHAPS") for existing fossil-fuel-fired Electrical Utility Steam Generating Units ("EGU's") (under 40 CFR 63 Subpart UUUUU). The regulation, known more commonly as the Mercury Air Toxics Standard ("MATS") was originally focused on limiting the amount of mercury and acid gas from the nation's coal-fired power plants. However, the regulation extends to oil-fired power plants as well. While our Hawaii refinery can be tuned, operated, and modified to respond to a shift in customer fuel specifications and additional demand for distillates, an ongoing surplus of residual fuels (produced by both Hawaii-based refineries) will likely put pressure on margins and necessitate alternative marketing and distribution strategies.

Fuel Standards

In 2007, the U.S. Congress passed the Energy Independence and Security Act ("EISA") which, among other things, set a target fuel economy standard of 35 miles per gallon for the combined fleet of cars and light trucks in the U.S. by model year 2020 and contained a second Renewable Fuel Standard (the "RFS2"). In August 2012, the EPA and National Highway Traffic Safety Administration jointly adopted regulations that establish an average industry fuel economy of 54.5 miles per gallon by model year 2025. The RFS2 requires an increasing amount of renewable fuel usage, up to 36.0 billion gallons by 2022. In the near term, we, like many other refiners, plan to satisfy the RSF2 requirement primarily by blending denatured ethanol fuel into gasoline. Since the RFS2 is applicable to diesel fuel as well as gasoline and since we did not blend in any biodiesel in 2014, we satisfied our overall RFS obligation through the acquisition of renewable credits referred to as Renewable Identification Numbers ("RINs"). The RFS2 may present production and logistics challenges for both the renewable fuels and petroleum refining and marketing industries in that we may have to enter into arrangements with other parties or purchase credits from the EPA to meet our obligations to use advanced biofuels, including biomass-based diesel and cellulosic biofuel, with potentially uncertain supplies of these new fuels and RINs.

In October 2010, the EPA issued a partial waiver decision under the CAA to allow for an increase in the amount of ethanol permitted to be blended into gasoline from 10% ("E10") to 15% ("E15") for 2007 and newer light duty motor vehicles. There are numerous issues, including state and federal regulatory issues, which need to be addressed before E15 can be marketed on a large scale for use in traditional gasoline engines. Consequently, unless the federal regulations are revised, qualified RINS will be required to fulfill the federal mandate for renewable fuels. We may experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

In March 2014, the EPA published a final Tier 3 gasoline standard that lowers the allowable sulfur level in gasoline to 10 parts per million ("ppm") and also lowers the allowable benzene, aromatics, and olefins content of gasoline. The effective date for the new standard was January 1, 2017, however, approved small volume refineries have until January 1, 2020 to meet the standard. Our Hawaii refinery is required to comply with Tier 3 gasoline standards within 30 months of June 21, 2016, the date our Hawaii refinery was disqualified from small volume refinery status. On March 19, 2015, the EPA confirmed the small refinery status of our Wyoming refinery.

Beginning on June 30, 2014, new sulfur standards for fuel oil used by marine vessels operating within 200 miles of the U.S. coastline (which includes the entire Hawaiian Island chain) was lowered from 10,000 ppm (1%) to 1,000 ppm (0.1%). The sulfur standards began at the Hawaii refinery and were phased in so that by January 1, 2015, they were to be fully aligned with the International Marine Organization ("IMO") standards and deadline. The more stringent standards apply universally to both U.S. and foreign flagged ships. Although the marine fuel regulations provided vessel operators with a few compliance options such as installation of on-board pollution controls and demonstration unavailability, many vessel operators will be forced to switch to a distillate fuel while operating within the Emission Control Area ("ECA"). Beyond the 200 mile ECA, large ocean vessels are still allowed to burn marine fuel with up to 3.5% sulfur. Our Hawaii refinery is capable of producing the 1% sulfur residual fuel oil that was previously required within the ECA. Although our Hawaii refinery remains in a position to supply vessels traveling to and through Hawaii, the market for 0.1% sulfur distillate fuel and 3.5% sulfur residual fuel is much more competitive.

There will be compliance costs and uncertainties regarding how we will comply with the various requirements contained in the EISA and other fuel-related regulations. Along with credit and trading options, potential capital upgrades for the Hawaii and Wyoming refineries are being evaluated. We may also experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

Solid and Hazardous Waste

Several of our businesses generate wastes, including hazardous wastes, which are subject to regulation under the federal Resource Conservation and Recovery Act ("RCRA") and state statutes. The EPA has limited the disposal options for certain hazardous wastes and state regulation of the handling and disposal of refining and natural gas and oil exploration and production wastes and solid wastes is becoming more stringent. Furthermore, it is possible that certain wastes generated by our natural gas and oil operations which are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes and therefore be subject to more rigorous and costly disposal requirements.

Naturally Occurring Radioactive Materials ("NORM") are radioactive materials that accumulate on production equipment or area soils during oil and natural gas extraction or processing. NORM wastes are regulated under the RCRA framework, although such wastes may qualify for the oil and gas hazardous waste exclusion. Primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage, and disposal of NORM waste; management of waste piles, containers, and tanks; and limitations upon the release of NORM-contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards.

Our natural gas and oil properties have been operated by third parties that controlled the treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to refineries and to natural gas and oil wastes and properties have gradually become stricter over time. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators) or to perform remedial operations to prevent future contamination.

Superfund

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release or threatened release of a "hazardous substance" into the environment. These persons include the current owner and operator of a site, any former owner or operator who operated the site at the time of a release, transporters, and persons that disposed or arranged for the disposal of hazardous substances at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs of such action. State statutes impose similar liability.

Under CERCLA, the term "hazardous substance" does not include "petroleum, including crude oil or any fraction thereof," unless specifically listed or designated and the term does not include natural gas, NGLs, liquefied natural gas, or synthetic gas usable for fuel. While this "petroleum exclusion" lessens the significance of CERCLA to our exploration and production operations, we may generate wastes that may fall within CERCLA's definition of a "hazardous substance" in the course of our ordinary refining and natural gas and oil operations. Although we and, to our knowledge, our predecessors have used operating and disposal practices that were standard in the industry at the time, "hazardous substances" may have been disposed or released on, under, or from the properties currently or historically owned or leased by us or on, under, or from other locations where these wastes have been taken for disposal. At this time, we do not believe that we have any liability associated with any Superfund site and we have not been notified of any claim, liability, or damages under CERCLA.

Oil Pollution Act

The Oil Pollution Act of 1990 ("OPA") and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of crude oil spills and liability for damages resulting from such spills in U.S. waters. A "responsible party" includes the owner or operator of a facility or vessel or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for crude oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction, or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA.

The OPA establishes a liability limit for onshore facilities of $633.85 million and for offshore facilities of all removal costs plus $133.65 million and lesser limits for some vessels depending upon their size. The regulations promulgated under OPA impose proof of financial responsibility requirements that can be satisfied through insurance, guarantee, indemnity, surety bond, letter of credit, qualification as a self-insurer, or a combination thereof. The amount of financial responsibility required depends upon a variety of factors including the type of facility or vessel, its size, storage capacity, throughput, proximity to sensitive areas, type of oil handled, history of discharges, and other factors. Failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. The federal Bureau of Ocean Energy Management ("BOEM") has proposed to increase the OPA liability limit for offshore facilities. Further, the U.S. Congress has considered legislation that could increase our obligations and potential liability under the OPA, including by eliminating the current cap on liability for damages and increasing minimum levels of financial responsibility. It is uncertain whether, and in what form, such legislation may ultimately be adopted. We are not aware of the occurrence of any action or event that would subject us to liability under OPA and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on us.

Discharges

The Clean Water Act ("CWA") regulates the discharge of pollutants to waters of the U.S., including wetlands, and requires a permit for the discharge of pollutants, including petroleum, to such waters. Certain facilities that store or otherwise handle oil are required to prepare and implement Spill Prevention, Control, and Countermeasure and Facility Response Plans relating to the possible discharge of oil to surface waters. We are required to prepare and comply with such plans and to obtain and comply with discharge permits. We believe we are in substantial compliance with these requirements and that any noncompliance would not have a material adverse effect on us. The CWA also prohibits spills of oil and hazardous substances to waters of the U.S. in excess of levels set by regulations and imposes liability in the event of a spill.

State laws further regulate discharges of pollutants to surface and groundwaters, require permits that set limits on discharges to such waters, and provide civil and criminal penalties and liabilities for spills to both surface and groundwaters. Some states have imposed regulatory requirements to respond to concerns related to potential for groundwater impact from oil and gas exploration and production. For example, the Colorado Oil and Gas Conservation Commission ("COGCC") approved rules that require sampling of groundwater for hydrocarbons and other indicator compounds both before and after drilling. Sampling results are to be reported to the COGCC, which maintains a water quality database online and available to the public.

Hydraulic Fracturing

Our and Laramie Energy's exploration and production activities may involve the use of hydraulic fracturing techniques to stimulate wells and maximize natural gas production. Citing concerns over the potential for hydraulic fracturing to impact drinking water, human health, and the environment and in response to a congressional directive, the EPA has commissioned a study to identify potential risks associated with hydraulic fracturing. In June 2015, the EPA released for public comment and peer review a draft assessment of the potential impacts of hydraulic fracturing on drinking water resources. Additionally, the draft generated substantial public comment and the EPA's Science Advisory Board scheduled public meetings and teleconferences through at least March 2016 to receive comment on the study. The study was intended to improve scientific understanding to guide the EPA's regulatory oversight, guidance, and, where appropriate, rulemaking related to hydraulic fracturing. The EPA study was released in December 2016 and it concluded that hydraulic fracturing activities can impact drinking water under certain circumstances, a conclusion that may lead to additional regulation. Some states and localities now regulate the utilization of hydraulic fracturing and other states and localities are in the process of developing, or are considering development of, such rules. In some states, courts are in the process of determining whether local bans or other regulation of oil and gas exploration and production activity are preempted by statewide regulatory programs. A state ballot initiative was introduced in Colorado to amend the state constitution to give local governments control over oil and natural gas drilling in their areas, but the ballot initiative failed. Additionally, the Colorado Supreme Court ruled in May 2016 that local governments in that state lacked authority to ban hydraulic fracturing. Given the results of the EPA study and other developments related to hydraulic fracturing, however, our and Laramie

Energy's drilling activities could be subjected to new or enhanced federal, state, and/or local regulatory requirements governing hydraulic fracturing, including requirements that would restrict the areas in which we are able to operate.

Air Emissions

Our refining operations and our and Laramie Energy's exploration and production operations are subject to local, state, and federal regulations for the control of emissions from sources of air pollution. Administrative enforcement actions for failure to comply strictly with air regulations or permits may be resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could impose civil and criminal liability for non-compliance. An agency could require us to forego construction or operation of certain air emission sources. We believe that we are in substantial compliance with air pollution control requirements and that, if a particular permit application were denied, we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

Our refining business is subject to very significant state and federal air permitting and pollution control requirements, including some that are the subject of ongoing enforcement activities by the EPA as described in more detail below. The EPA continues to review and, in many cases, tighten ambient air quality standards, which standards, along with the advancement of pollution control technologies, could result in new regulatory and permit requirements that will impact our refining activities and involve additional costs.

On September 29, 2015, the EPA announced a final rule updating standards that control toxic air emissions from petroleum refineries, addressing, among other things, flaring operations, fenceline air quality monitoring, and additional emission reductions from storage tanks and delayed coking units. Affected existing sources will be required to comply with the new requirements no later than 2018, with certain refiners required to comply earlier depending on the relevant provision and refinery construction date. We do not anticipate that compliance with this rule will have a material impact on our financial condition, results of operations, or cash flows.

With respect to our and Laramie Energy's exploration and production activities, the EPA has finalized rules to limit air emissions from many hydraulically fractured natural gas wells. These regulations require use of equipment to capture gases that come from such wells during the drilling process (so-called green completions). Other requirements, many effective in 2013, involved tighter standards for emissions associated with natural gas production, storage, and transport. In June 2016, the EPA published final rules to address methane emissions of new oil and gas wells and in November 2016, the Bureau of Land Management (“BLM”) published new rules to limit flaring on public and tribal lands. While these new requirements increased the cost of natural gas production, neither we nor Laramie Energy were affected any differently than other producers of natural gas.

More stringent regulation may be imposed in the future as a result of public concern about the impacts of increased oil and gas drilling activity and the availability of new information. For example, the Colorado Department of Natural Resources and the Colorado Department of Public Health and the Environment have announced plans for a study of emissions tied to oil and gas development in areas along the northern Front Range of the Rocky Mountains. Due to uncertainties regarding the outcome of such studies and potential new regulatory proposals, we are unable to predict the financial impact of such developments on our company going forward.

Coastal Coordination

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act (“CZMA”) was passed to preserve and, where possible, restore the natural resources of the coastal zone of the U.S. The CZMA provides for federal grants for state management programs that regulate land use, water use, and coastal development.

Environmental Agreement

On September 25, 2013 (the “Closing Date”), Par Petroleum, LLC (formerly known as Hawaii Pacific Energy; a wholly owned subsidiary of Par created for purposes of acquiring PHR), Tesoro, and PHR entered into an Environmental Agreement (“Environmental Agreement”), which allocated responsibility for known and contingent environmental liabilities related to the acquisition of PHR as follows:

Consent Decree

On July 18, 2016, PHR and subsidiaries of Tesoro entered into a consent decree with the EPA, the U.S. Department of Justice ("DOJ"), and other state governmental authorities concerning alleged violations of the federal CAA related to the ownership and operation of multiple facilities owned or formerly owned by Tesoro and its affiliates ("Consent Decree"), including our Hawaii refinery. As a result of the Consent Decree, PHR expanded its previously-announced 2016 Hawaii refinery turnaround to undertake additional capital improvements to reduce emissions of air pollutants and to provide for certain NOx and SO_2 emission controls and monitoring required by the Consent Decree. Although the turnaround was completed during the third quarter of 2016, work related to the Consent Decree is ongoing. This work subjects us to risks associated with engineering, procurement, and construction of improvements and repairs to our facilities and related penalties and fines to the extent applicable deadlines under the Consent Decree are not satisfied, as well as risks related to the performance of equipment required by, or affected by, the Consent Decree. Each of these risks could have a material adverse effect on our business, financial condition, or results of operations.

We estimate the cost of compliance with the Consent Decree to be approximately $30.0 million. However, Tesoro is responsible under the Environmental Agreement for directly paying, or reimbursing PHR, for all reasonable third-party capital expenditures incurred pursuant to the Consent Decree to the extent related to acts or omissions prior to the Closing Date. Tesoro is obligated to pay all applicable fines and penalties related to the Consent Decree.

As of December 31, 2017 , Tesoro has reimbursed us for $12.1 million of our total capital expenditures of $12.9 million incurred in connection with the Consent Decree. Net capital expenditures and reimbursements related to the Consent Decree are presented within Capital expenditures on our consolidated statement of cash flows for the years ended December 31, 2017 and 2016 . Please read Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Indemnification

In addition to its obligation to reimburse us for capital expenditures incurred pursuant to the Consent Decree, Tesoro agreed to indemnify us for claims and losses arising out of related breaches of Tesoro's representations, warranties, and covenants in the Environment Agreement, certain defined "corrective actions" relating to pre-existing environmental conditions, third-party claims arising under environmental laws for personal injury or property damage arising out of, or relating to, releases of hazardous materials that occurred prior to the Closing Date, any fine, penalty, or other cost assessed by a governmental authority in connection with violations of environmental laws by us prior to the Closing Date, certain groundwater remediation work, the replacement of underground storage tanks located at certain retail assets, fines, or penalties imposed on us by the Consent Decree related to acts or omissions of Tesoro prior to the Closing Date and related to the Pearl City Superfund Site.

Tesoro's indemnification obligations are subject to certain limitations as set forth in the Environmental Agreement. These limitations include a deductible of $1 million and a cap of $15 million for certain of Tesoro's indemnification obligations related to certain pre-existing conditions as well as certain restrictions regarding the time limits for submitting notice and supporting documentation for remediation actions.

Other Government Regulation

Sales and Transportation of Natural Gas

Historically, the transportation and sales for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA"), and Federal Energy Regulatory Commission ("FERC") regulations. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated the price for all "first sales" of natural gas. Thus, all of our sales of gas may be made at market prices, subject to applicable contract provisions. Sales of natural gas are affected by the availability, terms, and cost of pipeline transportation. Since 1985, the FERC has implemented regulations intended to make natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. We cannot predict what further action the FERC will take on these matters. Some of the FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers, and marketers with which we compete.

The Outer Continental Shelf Lands Act ("OCSLA"), which was administered by the Bureau of Ocean Energy Management, Regulation, and Enforcement ("BOEMRE") and, after October 1, 2011, its successors, the BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE"), and the FERC, requires that all pipelines operating on or across the shelf provide open-access, non-discriminatory service. There are currently no regulations implemented by the FERC under its OCSLA authority on gatherers and other entities outside the reach of its NGA jurisdiction. Therefore, we do not believe that any FERC, BOEM, or

BSEE action taken under OCSLA will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers, and marketers with which we compete.

Natural gas continues to supply a significant portion of North America's energy needs and we believe the importance of natural gas in meeting this energy need will continue, although natural gas supply and demand fundamentals have resulted in extremely volatile natural gas prices, which is expected to continue.

On August 8, 2005, the Energy Policy Act of 2005 ("2005 EPA") was signed into law. This comprehensive act contains many provisions that will encourage natural gas and oil exploration and development in the U.S. The 2005 EPA directs the FERC, BOEM, and other federal agencies to issue regulations that will further the goals set out in the 2005 EPA. The 2005 EPA amends the NGA to make it unlawful for "any entity", including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme, or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases, or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC's enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In 2007, the FERC issued a final rule on annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMbtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, and natural gas marketers, are now required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. The monitoring and reporting required by these rules have increased our administrative costs. We do not anticipate that we will be affected any differently than other producers of natural gas.

Our sales of crude oil, condensate, and natural gas liquids are not currently regulated and are subject to applicable contract provisions made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms, and conditions of service are subject to the FERC's jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms, and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate, and natural gas liquids is generally more light-handed than the FERC's regulation of gas pipelines under the NGA. Regulated pipelines that transport crude oil, condensate, and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation by the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, pipeline rates are subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge market-based rates if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Federal Leases

We maintain operations located on federal oil and natural gas leases, which are administered by the BOEMRE, BOEM, or BSEE, pursuant to the OCSLA. The BOEMRE and its successors, the BOEM and the BSEE, regulate offshore operations, including engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on offshore California, and removal of facilities.

On January 19, 2011, the U.S. Department of the Interior announced that it would divide offshore oil and gas responsibilities among three separate agencies, with the reorganization to be completed in 2011. The Department of the Interior first created the Office of Natural Resources Revenue ("ONRR") to manage revenue collection on October 1, 2010. Effective

October 1, 2011, the remaining functions of BOEMRE were split into two federal bureaus, the BOEM, which handles offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, NEPA analysis, and environmental studies and the BSEE, which is responsible for the safety and enforcement functions of offshore oil and gas operations, including the development and enforcement of safety and environmental regulations, permitting of offshore exploration, development, and production activities, inspections, offshore regulatory programs, oil spill response, and newly formed training and environmental compliance programs. Consequently, after October 1, 2011, we are required to interact with two federal bureaus to obtain approval of our exploration and development plans and issuance of drilling permits, which may result in added plan approval or drilling permit delays. Our federal oil and natural gas leases are awarded based on competitive bidding and contain relatively standardized terms. These leases require compliance with detailed BOEMRE regulations and orders that are subject to interpretation and change by the BOEM or BSEE. The BOEMRE has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures, and pipelines and the BOEM or the BSEE may in the future amend these regulations.

To cover the various obligations of lessees on the Outer Continental Shelf ("OCS"), the BOEMRE and its successors generally require that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial and there is no assurance that they can be obtained in all cases. We are currently exempt from supplemental bonding requirements. As many regulations are being reviewed, we may be subject to supplemental bonding requirements in the future. Under some circumstances, the BOEM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and results of operations.

The ONRR administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the ONRR.

Federal, State, or American Indian Leases

In the event we conduct operations on federal, state, or American Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the BLM, BOEM, or other appropriate federal or state agencies.

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the U.S. Such restrictions on citizens of a "non-reciprocal" country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation's lease can be cancelled in a proceeding instituted by the U.S. Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of our equity interests may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

State Regulations

Most states regulate the production and sale of oil and natural gas, including:

- requirements for obtaining drilling permits;
- the method of developing new fields;
- the spacing and operation of wells;
- the prevention of waste of oil and natural gas resources; and
- the plugging and abandonment of wells.

The rate of production may be regulated and the maximum daily production allowable from both oil and natural gas wells may be established on a market demand or conservation basis or both.

We may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such natural gas is produced, transported, and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such an event, the rates that we could charge for gas, the transportation of natural gas and oil, and the construction and operation of such pipeline would be subject to the rules and regulations governing such matters, if any, of such administrative authority.

For example, in August 2013, the COGCC implemented new setback rules for oil and natural gas wells and production facilities near occupied buildings. The COGCC increased its setback distance to a uniform 500 feet statewide setback from occupied buildings and a uniform 1,000 feet statewide setback from high occupancy building units. The new setback rules also require operators to utilize increased mitigation measures to limit potential drilling impacts to surface owners and the owners of occupied building units. The new rules also require operators to provide advance notice to surface owners within 500 feet of proposed operations, the owners of occupied buildings within 1,000 feet of proposed operations, and local governments prior to the filing of an Application for Permit to Drill or Oil and Gas Location Assessment. The new rules include expanded outreach and communication efforts by an operator.

In January 2013, the COGCC also approved two rules that require operators to sample groundwater for hydrocarbons and other indicator compounds both before and after drilling. The new statewide rule requires sampling of up to four water wells within a half mile radius of a new natural gas and oil well before drilling, two samples between six and 12 months after completion and two more samples between five and six years after completion. The revised rule for the Greater Wattenberg Area (“GWA”) requires operators to sample one water well per quarter governmental section before drilling and between six to 12 months after completion.

Legislative Proposals

In the past, the U.S. Congress has been very active in the area of natural gas regulation. New legislative proposals in the U.S. Congress and the various state legislatures, if enacted, could significantly affect the natural gas and oil industry. At the present time it is impossible to predict what proposals, if any, might actually be enacted by the U.S. Congress or the various state legislatures and what effect, if any, such proposals might have on our operations.

Impact of Dodd-Frank Act Derivatives Regulation

The Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank Act”), which was passed by the U.S. Congress and signed into law in July 2010, contains significant derivatives regulation, including requirements that certain transactions be cleared on exchanges and that collateral (commonly referred to as “margin”) be posted for such transactions. The Dodd-Frank Act provides for a potential exception from these clearing and collateral requirements for commercial end-users and it includes a number of defined terms used in determining how this exception applies to particular derivative transactions and the parties to those transactions. As required by the Dodd-Frank Act, the Commodities Futures and Trading Commission (“CFTC”) has promulgated numerous rules to define these terms. The CFTC has re-proposed new rules that would place limits on certain core futures and equivalent swap contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new positions limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

It is possible that the CFTC, in conjunction with prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral. If this should occur, we intend to manage our credit relationships to minimize collateral requirements.

The CFTC’s final rules may also have an impact on our hedging counterparties. For example, our bank counterparties may be required to post collateral and assume compliance burdens resulting in additional costs. We expect that much of the increased costs could be passed on to us, thereby decreasing the relative effectiveness of our hedges and our profitability. To the extent we incur increased costs or are required to post collateral, there could be a corresponding decrease in amounts available for our capital investment program.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendments and Reauthorization Act, and similar state statutes require us to organize and/or disclose information about hazardous materials used or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities, and local citizens.

SIGNIFICANT CUSTOMERS

We sell a variety of refined products to a diverse customer base. The majority of our refined products are primarily sold through short-term contracts or on the spot market. For the year ended December 31, 2017 , we had one customer in our refining segment that accounted for 10% of our consolidated revenues. No other customer accounted for more than 10% of our consolidated revenues during the years ended December 31, 2017 , 2016 , and 2015 .

EMPLOYEES

At December 31, 2017 , we employed 905 people, 149 of whom are nonexempt employees at the Hawaii refinery who are represented by the United Steelworkers Union (“USW”). Our previous collective bargaining agreement with the union expired in January 2015. On March 23, 2015, the union ratified a four-year extension of the collective bargaining agreement. On January 13, 2016, a claim against us was brought to the United States National Labor Relations Board (“NLRB”) alleging a refusal to bargain collectively and in good faith. Notwithstanding the pending claim before the NLRB, we consider our relations with our represented and non-represented employees to be satisfactory.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K may constitute “forward-looking” statements as defined in Section 27A of the Securities Act of 1933 (the “Securities Act”), Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”), the Private Securities Litigation Reform Act of 1995 (“PSLRA”), or in releases made by the SEC, all as may be amended from time to time. Such forward-looking statements involve known and unknown risks, uncertainties, and other important factors that could cause our actual results, performance, or achievements to differ materially from any future results, performance, or achievements expressed or implied by such forward-looking statements. Statements that are not historical fact are forward-looking statements. Forward-looking statements can be identified by, among other things, the use of forward-looking language, such as the words “plan,” “believe,” “expect,” “anticipate,” “intend,” “estimate,” “project,” “may,” “will,” “would,” “could,” “should,” “seeks,” or “scheduled to,” or other similar words or the negative of these terms or other variations of these terms or comparable language or by discussion of strategy or intentions. These cautionary statements are being made pursuant to the Securities Act, the Exchange Act, and the PSLRA with the intention of obtaining the benefits of the “safe harbor” provisions of such laws.

The forward-looking statements contained in this Annual Report on Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance and we cannot assure any reader that such statements will be realized or that the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in “ Item 1A. — Risk Factors ”, “ Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations ,” and elsewhere in this Annual Report on Form 10-K. All forward-looking statements speak only as of the date they are made. We do not intend to update or revise any forward-looking statements as a result of new information, future events, or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 1A. RISK FACTORS

Our businesses involve a high degree of risk. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Annual Report on Form 10-K. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, prospects, financial condition, results of operations, or cash flows could be materially adversely affected. In any such case, the trading price of our common stock could decline. The risks described below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us.

OPERATING RISKS

Our operations are subject to operational hazards that could expose us to potentially significant losses.

Our operations are subject to potential operational hazards and risks inherent in refining operations, in transporting and storing crude oil and refined products, and in producing natural gas and oil. Any of these risks, such as fires, explosions, maritime disasters, security breaches, pipeline ruptures and spills, mechanical failure of equipment, and severe weather and natural disasters at our or third-party facilities could result in business interruptions or shutdowns and damage to our properties and the properties of others. A serious accident at our facilities could also result in serious injury or death to our employees or contractors and could expose us to significant liability for personal injury claims and reputational risk. Any such event or unplanned shutdown could have a material adverse effect on our business, financial condition, and results of operations.

The volatility of crude oil prices and refined product prices and changes in the demand for such products may have a material adverse effect on our cash flow and results of operations.

Earnings and cash flows from our refining segment depend on a number of factors, including to a large extent the cost of crude oil and other refinery feedstocks which has fluctuated significantly in recent years. While prices for refined products are influenced by the price of crude oil, the constantly changing margin between the price we pay for crude oil and other refinery feedstocks and the prices we receive for refined products ("crack spread") also fluctuates significantly. The prices we pay and prices we receive depend on numerous factors beyond our control, including the global supply and demand for crude oil, gasoline, and other refined products, which are subject to, among other things:

- changes in the global economy and the level of foreign and domestic production of crude oil and refined products;
- availability of crude oil and refined products and the infrastructure to transport crude oil and refined products;
- local factors, including market conditions, the level of operations of other refineries in our markets, and the volume and price of refined products imported;
- threatened or actual terrorist incidents, acts of war, and other global political conditions;
- government regulations; and
- weather conditions, hurricanes, or other natural disasters.

In addition, we purchase our refinery feedstocks before manufacturing and selling the refined products. Price level changes during the period between purchasing feedstocks and selling the manufactured refined products from these feedstocks could have a significant impact on our financial results. We purchase refined products manufactured by others for sale to our customers. Price level changes during the periods between purchasing and selling these refined products could also have a material adverse effect on our business, financial condition, and results of operations.

Our investment in Laramie Energy is impacted by changing commodity prices. Laramie Energy primarily sells natural gas and natural gas liquids, and adverse changes in those commodity prices would impact the value of our investment in Laramie Energy.

Instability in the global economic and political environment can lead to volatility in the cost and availability of crude oil and prices for refined products, which could adversely impact our results of operations.

Instability in the global economic and political environment can lead to volatility in the cost and availability of crude oil and in the price for refined products. This may place downward pressure on our results of operations. This is particularly true of developments in and relating to oil-producing countries, including terrorist activities, military conflicts, embargoes, internal instability, or actions or reactions of the U.S. or foreign governments in anticipation of, or in response to, such developments. Any such events may limit or disrupt markets, which could negatively impact our ability to access global crude oil commodity flows or sell our refined products.

Many of our refined products could cause serious injury or death if mishandled or misused by us or our purchasers, or if defects occur during manufacturing.

While we produce, store, transport, and deliver all of our refined products in a safe manner, many of our refined products are highly flammable or explosive and could cause significant damage to persons or property if mishandled. Defects in our products (such as gasoline or jet fuel) or misuse by us or by end purchasers could lead to fatalities or serious damage to property. We may be held liable for such occurrences which could have a material adverse effect on our business and results of operations.

Our business is impacted by increased risks of spills, discharges, or other releases of petroleum or hazardous substances in our refining and logistics operations and in third-party natural gas and oil production operations in which we have a working interest.

The operation of refineries, pipelines, and refined products terminals and the production of natural gas and oil is subject to increased risks of spills, discharges, or other inadvertent releases of petroleum or hazardous substances. These events could occur in connection with the operation of our refineries, pipelines, or refined products terminals, or third-party drilling and production activities in which we have a working interest or at third-party facilities that receive our wastes or by-products for treatment or disposal. If any of these events occur, or is found to have previously occurred, we could be liable for costs and penalties associated with their remediation under federal, state, and local environmental laws or common law, and could be liable for property damage to third parties caused by contamination from releases and spills. The penalties and clean-up costs that we may have to pay for releases or the amounts that we may have to pay to third parties for damages to their property, could be significant and have a material adverse effect on our business, financial condition, or results of operations.

We operate in and adjacent to environmentally sensitive coastal waters where tanker, pipeline, and refined product transportation and storage operations are closely regulated by federal, state, and local agencies and monitored by environmental interest groups. Operations by third-party drilling and production entities in which we have a working interest that are adjacent to navigable waters such as rivers and lakes are similarly subject to stringent regulations. Transportation and storage of crude oil and refined products over and adjacent to regulated waters involves increased risk subjecting us to the provisions of the OPA and state laws in Hawaii, Wyoming, South Dakota, and Colorado. Among other things, these laws require us and the owners of tankers that we charter to deliver crude oil to our Hawaii refinery to demonstrate in some situations the capacity to respond to a spill of up to one million barrels of oil from a tanker and up to 600 thousand barrels of oil from an above-ground storage tank adjacent to water, which we refer to as a “Worst Case Discharge,” to the maximum extent possible.

We and third-party drilling and production entities in which we have a working interest and the owners of tankers we charter have contracted with various spill response service companies in the areas in which we transport and store crude oil and refined products to meet the requirements of the OPA and applicable state and foreign laws. However, there may be accidents involving tankers, pipelines, railcars, or above ground storage tanks transporting or storing crude oil or refined products, and response services may not respond to a Worst Case Discharge in a manner that will adequately contain that discharge, or we may be subject to liability in connection with any unauthorized discharge. Additionally, we cannot ensure that all resources of a contracted response service company could be available for our or a chartered tanker owner’s use at any given time. There are many factors that could inhibit the availability of these resources, including, but not limited to, weather conditions, governmental regulations or moratoria, or other global events. State or federal rulings could require that these resources could be diverted to respond to other events.

Our operations, including the operation of underground storage tanks, are also subject to the risk of environmental litigation and investigations which could affect our results of operations.

From time to time we have been, and presently are, subject to litigation and investigations with respect to environmental and related matters. We may become involved in further litigation or other proceedings, or we may be held responsible in any existing or future litigation or proceedings, the costs of which could be material.

We operate, and have in the past operated, fueling stations with underground storage tanks in Hawaii used primarily for storing and dispensing refined fuels. In addition, some of our fueling stations have been owned by third parties whose operation of the stations was not under our control.

Federal and state regulations and legislation govern the storage tanks and compliance with these requirements can be costly. The operation of underground storage tanks poses certain risks, including leaks. Leaks from underground storage tanks, which may occur at one or more of our fueling stations, may impact soil or groundwater and could result in fines or civil liability for us.

Our insurance coverage may be inadequate to protect us from the liabilities that could arise in our business.

We carry property, casualty, business interruption, and other lines of insurance but we do not maintain insurance coverage against all potential losses. Marine vessel charter agreements do not include indemnity provisions for oil spills so we also carry marine charterer's liability insurance. We could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Claims covered by insurance are subject to deductibles, the aggregate amount of which could be material. Insurance policies are also subject to compliance with certain conditions, the failure of which could lead to a denial of coverage as to a particular claim or the voiding of a particular insurance policy. There also can be no assurance that existing insurance coverage can be renewed at commercially reasonable rates or that available coverage will be adequate to cover future claims. The occurrence of an event that is not fully covered by insurance or failure by one or more insurers to honor its coverage commitments for an insured event could have a material adverse effect on our business, financial condition, and results of operations.

We are subject to interruptions of supply and increased costs as a result of our reliance on third-party transportation of crude oil and refined products to and from our Hawaii refinery.

Our Hawaii refinery receives its crude oil via tankers and transports refined products from Oahu to Hawaii, Maui, Molokai, and Kauai via barge. In addition to environmental risks, we could experience an interruption of supply or an increased cost to deliver refined products to market if the ability of the pipelines or vessels to transport crude oil or refined products is disrupted because of accidents, governmental regulation, or third-party action. A prolonged disruption of the ability of a pipeline or vessels to transport crude oil or refined products could have a material adverse effect on our business, financial condition, and results of operations.

The financial and operating results for our refineries in Hawaii and Wyoming, including the products they refine and distribute, can each be seasonal.

The operating results of each of our refineries, including the products they refine and sell, can be seasonal. Demand for gasoline in Wyoming and South Dakota is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. Wyoming Refining's financial and operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year as a result of this seasonality. Conversely, the demand for the products the Hawaii refinery refines and sells, and the financial and operating results for the Hawaii refinery, are often strongest in the first and fourth calendar quarters.

We rely upon certain critical information systems for the operation of our business and the failure of any critical information system, including a cyber security breach, may result in harm to our business.

We are heavily dependent on our technology infrastructure and maintain and rely upon certain critical information systems for the effective operation of our business. These information systems include data network and telecommunications, internet access and our websites, and various computer hardware equipment and software applications, including those that are critical to the safe operation of our refineries and our pipelines and terminals. Our retail business collects certain customer data, including credit card numbers, for business purposes. The integrity and protection of our customer, employee, and company data is critical to our business.

Our information systems are subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cyber attacks, and other events. To the extent that these information systems are under our control, we have implemented measures such as virus protection software and intrusion detection systems, to address the outlined risks. However, security measures for information systems cannot be guaranteed to be failsafe. Any compromise of our data security or our inability to use or access these information systems at critical points in time could unfavorably impact the timely and efficient operation of our business and subject us to additional costs and liabilities, which could adversely affect our business, financial condition, and results of operations. Finally, federal legislation relating to cyber security threats could impose additional requirements on our operations.

Through Laramie Energy, we are subject to all the risks of natural gas and oil exploration and production.

Through our investment in Laramie Energy and, to a lesser extent, through our other non-operated properties, we are exposed to all the risks inherent in natural gas and oil exploration and production, including the risks that:

- we may not be able to replace production with new reserves;
- exploration and development drilling may not result in commercially productive reserves;
- title to properties in which we or Laramie Energy have interest may be impaired by title defects;
- the marketability of our natural gas products depends mostly on the availability, proximity, and capacity of natural gas gathering systems, pipelines, and processing facilities, which are owned by third parties;

- we have no long-term contracts to sell natural gas or oil;
- compliance with environmental and other governmental requirements could result in increased costs of operation or curtailment, delay, or cancellation of development and producing operations;
- federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays;
- changes in the demand for natural gas and oil could adversely affect our financial condition and results of operations; and
- natural gas drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water when it flows back to the wellbore. If we are unable to obtain adequate water supplies and dispose of the water we use or remove at a reasonable cost and within applicable environmental rules, our ability to produce natural gas commercially and in commercial quantities would be impaired.

We cannot control activities on properties we do not operate and we are unable to ensure the proper operation and profitability of these non-operated properties.

We are a non-operator with respect to our natural gas and oil properties. Consequently, we have limited ability to exercise influence over, and control the risks associated with, the operation of these properties. The success and timing of leasehold acquisition, drilling, and development activities therefore will depend upon a number of factors outside of our control, including:

- timing and amount of capital expenditures;
- expertise and diligence in adequately performing operations and complying with applicable agreements;
- financial resources;
- inclusion of other participants in drilling wells; and
- use of technology.

As a result of any of the above, or any other failure of the operator to act in ways that are in our best interest, our results of operations and financial results could be adversely affected.

Our ability to extract value from our investment in Laramie Energy is limited.

Our 42.3% ownership interest in Laramie Energy is a significant asset. However, the ability of Laramie Energy to make distributions to its owners, including us, is currently prohibited by the terms of Laramie Energy's credit facility.

Information concerning our natural gas and oil reserves is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The accuracy of an estimate of quantities of natural gas and crude oil reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future natural gas and crude oil prices, availability and terms of financing, expenditures for future development and exploitation activities, and engineering and geological interpretation and judgment. Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities, natural gas and crude oil prices, and regulatory changes. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves, and value of cash flows from those reserves may vary significantly from our assumptions and estimates. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same data. These uncertainties may inhibit our ability to finance development of our reserves in the future.

The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves as of December 31, 2017 , included herein were prepared by independent reserve engineers in accordance with the rules of the SEC and are not intended to represent the fair market value of such reserves. As required by the SEC, the estimated discounted present value of future net cash flows from proved reserves is generally based on prices and costs on the date of the estimate, while actual future prices and costs may be materially higher or lower. In addition, the 10% discount factor the SEC requires to be used to calculate discounted future net revenues for reporting purposes is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the natural gas and oil industry in general.

Under current SEC requirements, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves we own indirectly through our equity investment in Laramie Energy as Laramie Energy pursues its drilling program. Moreover, we may be required to write down our proved undeveloped reserves we own indirectly through our equity investment in Laramie Energy, or we may be required to write down previously disclosed proved undeveloped reserves, if Laramie Energy does not drill and develop those reserves within the required five-year time frame.

REGULATORY RISK

Meeting the requirements of evolving environmental, health, and safety laws and regulations including those related to climate change could adversely affect our performance.

Consistent with the experience of other U.S. refineries, environmental laws and regulations have raised operating costs and may require significant capital investments at our refineries. We may be required to address conditions that may be discovered in the future and require a response. Potentially material expenditures could be required in the future as a result of evolving environmental, health, and safety and energy laws, regulations, or requirements that may be adopted or imposed in the future, as well as work that is ongoing related to the Consent Decree. Future developments in federal and state laws and regulations governing environmental, health, and safety and energy matters are especially difficult to predict.

Currently, multiple legislative and regulatory measures to address GHG emissions (including CO_2, methane, and nitrous oxides) are in various phases of consideration, promulgation, or implementation. These include actions to develop national, statewide, or regional programs, each of which could require reductions in our GHG emissions. Requiring reductions in our GHG emissions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls at our facilities, and/or (iii) administer and manage any GHG emissions programs, including acquiring emission credits or allotments.

Requiring reductions in our GHG emissions and increased use of renewable fuels which can be supplied by producers and marketers in other industries that supply alternative forms of energy and fuels to satisfy the requirements of our industrial, commercial, and individual customers could also decrease the demand for our refined products and could have a material adverse impact on our business, financial condition, and results of operations.

We could be held responsible in the future for decommissioning liabilities for offshore interests we no longer own.

Under state and federal law, oil and gas companies are obligated to plug and abandon (“P&A”) a well and restore the lease to pre-operating conditions after operations cease. U.S. state and federal regulations allow the government to call upon predecessors in interest of oil and gas leases to pay for P&A, restoration, and decommissioning obligations if the current operator fails to fulfill those obligations, the costs of which could be significant. On March 23, 2016, we assigned our interests in the Point Arguello Unit offshore California to Whiting Oil and Gas Corporation; however, the federal BOEM could call upon us to fulfill the P&A obligations related to these divested assets if the then current lessee of those assets is unable to fulfill their obligations.

Renewable fuels mandates may reduce demand for the petroleum fuels we produce, which could have a material adverse effect on our business results of operations and financial condition.

The EPA has issued Renewable Fuel Standard (“RFS”) mandates, requiring refiners such as us to blend renewable fuels into the petroleum fuels we produce and sell in the U.S. We, and other refiners subject to the RFS, may meet the RFS requirements by blending the necessary volumes of renewable fuels produced by us or purchased from third parties. To the extent that refiners will not or cannot blend renewable fuels into the products they produce in the quantities required to satisfy their obligations under the RFS program, those refiners must purchase renewable credits, referred to as RINs, to maintain compliance. To the extent that we exceed the minimum volumetric requirements for blending of renewable fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFS compliance or selling those RINs on the open market.

Under the RFS program, the volume of renewable fuels that obligated parties are required to blend into their finished petroleum fuels increases annually over time until 2022. Our refineries are subject to compliance with the RFS mandates. On November 30, 2015, the EPA issued final volume mandates for years 2014 through 2016, which are generally lower than the corresponding statutory mandates for those years.

Existing laws, regulations or regulatory initiatives could change and, notwithstanding that the EPA’s proposed volume mandates for 2014 through 2016, are generally lower than the corresponding statutory mandate for those years, the final minimum volumes of renewable fuels that must be blended with refined petroleum fuels could increase in the future. Despite a decline in RINs prices from relatively higher levels observed during mid-2013, we cannot currently predict the future prices of RINs and, thus, the expenses related to acquiring RINs in the future could increase relative to the cost in prior years. During 2017 , we incurred $9.3 million and $7.7 million for RINs for our Hawaii and Wyoming refineries, respectively. We expect to incur approximately $7.0 million for RINs in 2018 for each of our refineries. Any increase in the final minimum volumes of renewable fuels that must be blended with refined petroleum fuels and/or any increase in the cost to acquire RINs has the potential to result in significant costs in connection with RFS compliance for 2018 and future years, which could be material and may have a material adverse impact on our business, financial condition, and results of operations. Finally, while there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties, we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFS requirements. However, if this belief proves incorrect and the RINs that we purchase are not valid or in compliance with applicable RFS requirements, our financial condition and cash flows may be adversely affected.

Potential legislative and regulatory actions addressing climate change could increase our costs, reduce our revenue and cash flow from natural gas and oil sales, or otherwise alter the way we conduct our business.

The EPA has issued a notice of finding and determination that emissions of CO_2, methane, and other GHG present an endangerment to human health and the environment. In response, the EPA has adopted regulations under existing provisions of the federal CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit program requiring reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. Moreover, on December 23, 2010, the EPA entered a settlement agreement with environmental groups requiring the agency to propose by December 10, 2011 GHG New Source Performance Standards ("NSPS") for refineries and to finalize these rules by November 15, 2012. To date, the EPA has not completed those rulemakings and we do not know when they will be completed. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified large GHG emission sources in the U.S., including petroleum refineries and certain onshore petroleum and natural gas production activities, on an annual basis. We monitor for GHG emissions at our refineries and believe we are in substantial compliance with the applicable GHG reporting requirements. Certain of the third-party drilling and production entities in which we hold a working interest also may be subject to reporting of GHG emissions in the U.S. These EPA policies and rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In addition, from time to time, the U.S. Congress has considered, and may in the future consider and adopt "cap and trade" legislation that would establish an economy-wide cap on GHG emissions in the U.S. and would require most sources of GHG emissions to obtain emission "allowances" corresponding to their annual GHG emissions. For those GHG sources that are unable to meet the required limitations, such legislation could impose substantial financial burdens. Any laws or regulations that may be adopted to restrict or reduce GHG emissions would likely require us to incur increased operating costs and could have an adverse effect on demand for our production. The adoption of any legislation or regulations that limits emissions of GHG from our or such drilling and production entities' facilities, equipment, and operations could require us or such entities to incur costs to reduce emissions of GHG associated with our or such entities' operations or could adversely affect demand for the refined petroleum products that we produce or the crude oil or natural gas that such drilling and production entities in which we hold a working interest produce. Such regulations, if adopted, could increase costs of oil and natural gas operators, including Laramie Energy, in whom we have a non-operating working interest. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG 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 our operations, as well as on third-party drilling and production activities in which we have a non-operating working interest.

In connection with the WRC Acquisition , we will be required to undertake significant remediation and other corrective actions with respect to certain environmental matters.

In connection with the WRC Acquisition , there are several environmental conditions that will require us to undertake significant remediation efforts and other corrective actions. The Wyoming refinery is subject to a number of consent decrees, orders, and settlement agreements involving the EPA and/or the Wyoming Department of Environmental Quality, some of which date back to the late 1970s and several of which remain in effect, requiring further actions at the Wyoming refinery.

As is typical of older small refineries like the Wyoming refinery, the largest cost component arising from these various decrees relates to the investigation, monitoring, and remediation of soil, groundwater, surface water, and sediment contamination associated with the facility's historic operations. Investigative work by Wyoming Refining and negotiations with the relevant agencies as to remedial approaches remain ongoing on a number of aspects of the contamination, meaning that investigation, monitoring, and remediation costs are not reasonably estimable for some elements of these efforts. As of December 31, 2017 , we have accrued $18.2 million for the well-understood components of these efforts based on current information, approximately one-third of which we expect to incur in the next five years and the remainder being incurred over approximately 30 years.

Additionally, we believe the Wyoming refinery will need to modify or close a series of wastewater impoundments in the next several years and to replace those impoundments with a new wastewater treatment system. Based on preliminary information, reasonable estimates we have received suggest costs of approximately $11.6 million to design and construct a new wastewater treatment system.

Finally, among the various historic consent decrees, orders, and settlement agreements into which the Wyoming refinery has entered, there are several penalty orders associated with exceedances of permitted limits by the Wyoming refinery's wastewater discharges. Although the frequency of these exceedances appears to be declining over time, we may become subject to new penalty enforcement action in the next several years, which could involve penalties in excess of $100,000. Moreover, in November 2016 the Pipeline and Hazardous Materials Safety Administration ("PHMSA") conducted an integrated inspection of the products pipeline that we acquired in the WRC Acquisition. As a result of compliance violations identified during the inspection, the Wyoming refinery was assessed a civil penalty of $279 thousand in December 2017, which was paid in January 2018.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to manage risks associated with our businesses and increase the working capital requirements to conduct these activities.

The Dodd-Frank Act, which was passed by the U.S. Congress and signed into law in July 2010, provides for new statutory and regulatory requirements for derivative transactions, including crude oil and natural gas derivative transactions. Among other things, the Dodd-Frank Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has re-proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

It is not possible at this time to predict with certainty the full effect of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act may require us to comply with margin requirements and with certain clearing and trade-execution requirements if we do not satisfy certain specific exceptions. Although we expect to qualify for the end-user exception to the clearing, trade execution, and margin requirements for swaps entered to hedge our commodity risks, the application of the requirements to other market participants, such as swap dealers, may change the cost and availability of our derivatives. Depending on the rules adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provide cash collateral for our commodities derivative transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute transactions to reduce commodity price risk and thus protect cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until all of the regulations are implemented. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable. In addition, the Dodd-Frank Act was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

If our pipeline assets become subject to FERC regulation, or federal, state, or local regulations or policies change, our financial condition, results of operations, and cash flows could be materially and adversely affected.

We own and operate a crude oil gathering system and related storage facilities in Wyoming, as well as a refined products pipeline that transports product from our Wyoming refinery to a common carrier with access to Rapid City, South Dakota. We also own and operate a jet fuel storage facility and pipeline that serves Ellsworth Air Force Base in South Dakota. Under the federal Interstate Commerce Act (the "ICA"), there is no exemption for the gathering of crude oil or refined products. Whether a crude oil or refined products shipment is in interstate commerce under the ICA depends on the fixed and persistent intent of the shipper as to the crude oil's or refined products' final destination, absent a break in the interstate movement. We believe that the crude oil and refined products pipelines in our gathering system meet the traditional tests the FERC has used to determine that a pipeline is not providing transportation service in interstate commerce subject to FERC ICA jurisdiction. However, the determination of the interstate or intrastate character of shipments on our crude oil and refined products pipelines depends on the shipper's intentions and the transportation of the crude oil or refined products outside of our system, and may change over time. If the FERC were to consider the status of an individual facility and the character of a crude oil or refined product shipment, and determine that the shipment is in interstate commerce, the rates for, and terms and conditions of, transportation services provided by such facility would be subject to regulation by the FERC under the ICA. Such FERC regulation could decrease revenue, increase operating costs, and, depending on the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the ICA, this could result in the imposition of administrative and criminal remedies and civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas" ("HCAs"), which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources, and unusually sensitive ecological areas. These regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration, and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, certain states have also adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. These requirements could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in us incurring increased operating costs that could be significant and have a material adverse effect on our financial position or results of operations.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated operators. For instance, in January 2017, PHMSA finalized new regulations for hazardous liquid pipelines that significantly extend and expand the reach of certain PHMSA integrity management requirements (i.e., periodic assessments, repairs, and leak detection), regardless of the pipeline's proximity to an HCA. The final rule also requires all pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes, or other similar events that are likely to damage infrastructure. The timing for implementation of this rule is uncertain at this time due to the recent change in U.S. Presidential administrations. The safety enhancement requirements and other provisions of the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, as well as any implementation of PHMSA rules thereunder, could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our financial position or results of operations.

BUSINESS RISKS

The locations of our refineries and related assets in the Hawaiian Islands and in Newcastle, Wyoming, create an exposure to the risks of the local economies in which we operate and other local adverse conditions. Additionally, the location of our Hawaii refinery creates the risk of lower margins should the supply/demand balance change in the Hawaiian Islands requiring that we deliver refined products to customers outside of the region.

Because of the locations of our two refineries in Hawaii and Wyoming, we primarily market our refined products in relatively limited geographic areas. As a result, we are more susceptible to regional economic conditions than the operations of more geographically diversified competitors and any unforeseen events or circumstances that affect our operating area could also materially adversely affect our revenues and our business and operating results. These factors include, among other things, changes in the economy, weather conditions, demographics and population, increased supply of refined products from competitors, and reductions in the supply of crude oil.

Additionally, should the supply and demand balance shift in Hawaii, resulting in supply on the islands exceeding demand, we may have to deliver refined products to customers off-island. These sales generally result in lower margins to us relative to on-island sales given the higher cost of freight and typically lower price points.

We must make substantial capital expenditures at our refineries and related assets to maintain their reliability and efficiency. If we are unable to complete capital projects at their expected costs or in a timely manner, or if the market conditions assumed in our project economics deteriorate, our financial condition, results of operations, or cash flows could be adversely affected.

Our refineries and related assets have been in operation for many years. Equipment, even if properly maintained, may require significant capital expenditures and expenses to keep the refineries operating at optimum efficiency. These costs do not result in increases in unit capacities, but rather are focused on trying to maintain safe, reliable operations.

Delays or cost increases related to the engineering, procurement, and construction of new facilities, or improvements and repairs to our existing facilities and equipment, could have a material adverse effect on our business, financial condition, or results of operations. Such delays or cost increases may arise as a result of unpredictable factors in the marketplace, many of which are beyond our control, including:

- denial or delay in obtaining regulatory approvals and/or permits;
- difficulties in executing the capital projects;
- unplanned increases in the cost of equipment, materials, or labor;
- disruptions in transportation of equipment and materials;
- severe adverse weather conditions, natural disasters, or other events (such as equipment malfunctions, explosions, fires, or spills) affecting our facilities, or those of our vendors and suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and/or
- non-performance or force majeure by, or disputes with, our vendors, suppliers, contractors, or sub-contractors.

Any one or more of these occurrences noted above could have a significant impact on our business. If we are unable to make up the delays or to recover the related costs, or if market conditions change, it could materially and adversely affect our financial position, results of operations, or cash flows.

If we are unable to obtain our crude oil supply for our Hawaii refinery without the benefit of our Supply and Offtake Agreements with J. Aron, the capital required to finance our crude oil supply could negatively impact our liquidity.

All of the crude oil delivered at our Hawaii refinery is subject to our Supply and Offtake Agreements with J. Aron. If we are unable to obtain our crude oil supply for our Hawaii refinery outside these agreements, our exposure to crude oil pricing risks may increase as the number of days between when we pay for the crude oil and when the crude oil is delivered to us increases. Such increased exposure could negatively impact our liquidity position due to the increase in working capital used to acquire crude oil inventory for our Hawaii refinery.

The ongoing work related to the Consent Decree subjects us to risks associated with engineering, procurement, and construction of improvements and repairs to our facilities, related penalties and fines, and the performance of equipment, all of which could have a material adverse effect on our business, financial condition, or results of operations .

On July 18, 2016, PHR and subsidiaries of Tesoro entered into the Consent Decree. As a result of the Consent Decree, PHR expanded its previously-announced 2016 Hawaii refinery turnaround to undertake additional capital improvements to reduce emissions of air pollutants and to provide for certain NOx and SO_2 emission controls and monitoring required by the Consent Decree. Although the turnaround was completed during the third quarter of 2016, work related to the Consent Decree is ongoing. This work subjects us to risks associated with engineering, procurement, and construction of improvements and repairs to our facilities and related penalties and fines to the extent applicable deadlines under the Consent Decree are not satisfied, as well as risks related to the performance of equipment required by, or affected by, the Consent Decree. Each of these risks could have a material adverse effect on our business, financial condition, or results of operations.

Our arrangement with J. Aron exposes us to J. Aron-related credit and performance risk.

We have Supply and Offtake Agreements with J. Aron, pursuant to which J. Aron will intermediate crude oil supplies and refined product inventories at our Hawaii refinery. J. Aron will own all of the crude oil in our tanks and substantially all of our refined product inventories prior to our sale of the inventories. Upon termination of the Supply and Offtake Agreements, which may be terminated by J. Aron as early as May 31, 2021 , we are obligated to repurchase all crude oil and refined product inventories then owned by J. Aron and located at the specified storage facilities at then current market prices. Relying on J. Aron’s ability to honor its supply and offtake obligations exposes us to J. Aron’s credit and business risks. An adverse change in J. Aron’s business, results of operations, liquidity, or financial condition could adversely affect its ability to perform its obligations, which could consequently have a material adverse effect on our business, results of operations, or liquidity and, as a result, our business and operating results. In addition, we may be required to use substantial capital to repurchase crude oil and refined product inventories from J. Aron upon termination of the agreements, which could have a material adverse effect on our business, results of operations, or financial condition.

Our retail business is vulnerable to risks including changes in consumer preferences and economic conditions, competitive environment, supplier concentration, and other trends and factors that could harm our business, financial condition, and results of operations.

Our retail business is subject to changes in consumer preferences, national, regional, and local economic conditions, demographic trends, and consumer confidence in the economy. Factors such as traffic patterns, weather conditions, local demographics, and the number and locations of competing fueling stations and convenience stores also affect the performance of our retail stores. Adverse changes in any of these trends or factors could reduce our retail customer traffic or sales, or impose limits on our pricing that could adversely affect our business, financial condition, and results of operations.

We cannot be certain that our net operating loss tax carryforwards will continue to be available to offset our tax liability.

As of December 31, 2017 , we estimated that we had approximately $1.6 billion of net operating loss tax carryforwards (“NOLs”) . In order to utilize the NOLs, we must generate taxable income that can offset such carryforwards. The availability of NOLs to offset taxable income would be substantially reduced or eliminated if we were to undergo an “ownership change” within the meaning of Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”). We will be treated as having had an “ownership change” if there is more than a 50% increase in stock ownership during any three year “testing period” by “5% shareholders.”

In order to help us preserve our NOLs, our certificate of incorporation contains stock transfer restrictions designed to reduce the risk of an ownership change for purposes of Section 382 of the Code. We expect that the restrictions will remain in place for the foreseeable future. We cannot assure you, however, that these restrictions will prevent an ownership change.

Our ability to utilize our NOLs to offset future taxable income is subject to various limitations, including that the NOLs will expire in various amounts, if not used, between 2027 through 2036 . The Internal Revenue Service (“IRS”) has not audited any of our tax returns for any of the years during the carryforward period, including those returns for the years in which the losses giving rise to the NOLs were reported. We cannot assure you that we would prevail if the IRS were to challenge the availability of the NOLs. If the IRS were successful in challenging our NOLs, all or some portion of the NOLs would not be available to offset any future consolidated income which would negatively impact our results of operations and cash flows.

Recent changes in United States federal income tax law may have an adverse effect on our cash flows, results of operations, or financial condition overall.

The final version of the tax reform bill signed into law on December 22, 2017 (the “Tax Cuts and Jobs Act”) may affect our results of operations and financial condition. The Tax Cuts and Jobs Act, among other things, contains significant changes to corporate taxation, including (a) a reduction of the corporate tax rate from a top marginal rate of 35% to a flat rate of 21%, (b) limitation of the tax deduction for net interest expense to 30% of adjusted earnings (except for certain small businesses), (c) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, in each case, for losses arising in taxable years beginning after December 31, 2017 (though any such net operating losses may be carried forward indefinitely), and (d) the repeal of the domestic production activities deduction. From a financial statement point of view, we have adjusted our deferred tax assets in accordance with the new statutory corporate income tax rate (the net operating losses giving rise to such deferred tax assets remain subject to the 20 year carry forward limitation although such losses are not subject to the 80% of current year taxable income limitation described above). Given the scope of this law and the potential interdependency of its changes, it is difficult at this time to assess the overall effect of the Tax Cuts and Jobs Act, but such changes may adversely impact our financial results.

Certain federal income and excise taxes could change under future legislation.

In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to companies in the energy industry. Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation, including increases in certain fuel excise taxes or enacting proposed carbon taxes. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal tax laws could have an adverse effect on our financial position, results of operations, and cash flows.

Inadequate liquidity could materially and adversely affect our business operations in the future.

If our cash flow and capital resources are insufficient to fund our obligations, we may be forced to reduce our capital expenditures, seek additional equity or debt capital, or restructure our indebtedness. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. Our liquidity is constrained by our need to satisfy our obligations under our debt agreements and our Supply and Offtake Agreements. The availability of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, the crack spread, natural gas and crude oil prices, our credit ratings, interest rates, market perceptions of us or the industries in which we operate, our market value, and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these or other sources when the need arises.

Our ability to generate cash and repay our indebtedness or fund capital expenditures depends on many factors beyond our control and any failure to do so could harm our business, financial condition, and results of operations.

Our ability to fund future capital expenditures and repay our indebtedness when due will depend on our ability to generate sufficient cash flow from operations, borrowings under our debt agreements, and distributions from our subsidiaries. To a certain extent, this is subject to general economic, financial, competitive, legislative, and regulatory conditions and other factors that are beyond our control, including the crack spread and the prices we receive for our natural gas and crude oil production.

We cannot assure you that our businesses will generate sufficient cash flow from operations, that our subsidiaries can or will make sufficient distributions to us, or that future borrowings will be available to us in an amount sufficient to repay our indebtedness or fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our needs, we may be forced to reduce our planned capital expenditures, sell assets, seek additional equity or debt capital, or restructure our debt. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all, which could cause us to default on our obligations and could impair our liquidity.

Our substantial level of indebtedness could adversely affect our financial condition.

We have a substantial amount of indebtedness, which requires significant interest payments. As of December 31, 2017, we had $384.8 million of indebtedness, and Interest expense and financing costs, net for the year ended December 31, 2017 was $31.6 million .

Our substantial level of indebtedness could have important consequences, including the following:

- we must use a substantial portion of our cash flow from operations to pay interest and principal on our indebtedness and obligations under the Supply and Offtake Agreements, which reduces funds available to us for other purposes, such as working capital, capital expenditures, other general corporate purposes, and potential acquisitions;
- our ability to refinance such indebtedness or to obtain additional financing for working capital, capital expenditures, acquisitions, or general corporate purposes may be impaired;
- our leverage may be greater than that of some of our competitors, which may put us at a competitive disadvantage and reduce our flexibility in responding to current and changing industry and financial market conditions;
- we may be more vulnerable to economic downturns and adverse developments in our business; and
- we may be unable to comply with financial and other restrictive covenants in our debt agreements, some of which require us to maintain specified financial ratios and limit our ability to incur additional debt and sell assets, which could result in an event of default that, if not cured or waived, would have an adverse effect on our business and prospects and could result in bankruptcy.

Our ability to meet expenses, to remain in compliance with the covenants under our debt agreements, and to make future principal and interest payments in respect of our debt depends on, among other things, our operating performance, competitive developments, and financial market conditions, all of which are significantly affected by financial, business, economic and other factors. We are not able to control many of these factors. If industry and economic conditions deteriorate, our cash flow may not be sufficient to allow them to pay principal and interest on our debt and meet our other obligations.

Despite our current debt levels, we may still incur substantially more debt or take other actions which would intensify the risks associated with our substantial leverage.

Despite our current consolidated debt levels, we may be able to incur significant additional indebtedness in the future. Although our debt agreements contain restrictions on the incurrence of additional indebtedness and entering into certain types of other transactions, these restrictions are subject to a number of qualifications and exceptions. Additional indebtedness incurred in compliance with these restrictions could be substantial. These restrictions also do not prevent us or our subsidiaries from incurring obligations, such as trade payables, that do not constitute indebtedness as defined under our debt agreements. To the extent new debt is added to our current debt levels, the substantial leverage risks associated with our indebtedness would increase.

Servicing our debt requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial debt.

Our ability to make scheduled payments of the principal of, to pay interest on, or to refinance our indebtedness depends on our future performance, which is subject to economic, financial, competitive, and other factors beyond our control. Our business may not continue in the future to generate cash flow from operations that is sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as selling assets, restructuring debt, or obtaining additional equity capital on terms that may be onerous or highly dilutive. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at such time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations.

Our debt agreements impose significant operating and financial restrictions on us.

Our debt agreements impose, and the terms of any future debt may impose, significant operating and financial restrictions on us. These restrictions, among other things, may limit our ability to:

- pay dividends or distributions, repurchase equity, prepay junior debt, and make certain investments;
- incur additional debt or issue certain disqualified stock and preferred stock;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- incur liens on assets;
- merge or consolidate with another company or sell all or substantially all assets;
- enter into certain transactions with affiliates; and
- enter into agreements that would restrict the ability of our subsidiaries to pay dividends or make other payments to the Issuers.

All of these covenants may adversely affect our ability to finance our operations, meet or otherwise address our capital needs, pursue business opportunities, react to market conditions, or otherwise restrict activities or business plans. A breach of any of these covenants could result in a default in respect of the related indebtedness. If a default occurs, the requisite lenders could elect to declare the indebtedness, together with accrued interest and other fees, to be immediately due and payable and proceed against any collateral securing that indebtedness. If repayment of our indebtedness is accelerated as a result of such default, we cannot assure you that they would have sufficient assets or access to credit to repay such indebtedness.

We may incur losses and incur additional costs as a result of our forward-contract activities and derivative transactions.

We enter into derivative contracts from time to time primarily to reduce our exposure to fluctuations in interest rates and in the price of crude oil and refined products. If the instruments we use to hedge our exposure are not effective, or if our counterparties are unable to satisfy their obligations to us, we may incur losses. The risk of counterparty default is heightened in a poor economic environment. We may also be required to incur additional costs in connection with future regulation of derivative instruments to the extent such regulation is applicable to us. Additionally, our commodity derivative activities may produce significant period-to-period earnings volatility that is not necessarily reflective of our underlying operational performance.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

We are subject to interest rate risk in connection with borrowings under certain of our debt agreements, which bear interest at variable rates. Interest rate changes will not affect the market value of indebtedness incurred under such debt agreements, but could affect the amount of our interest payments and, accordingly, our future earnings and cash flows, assuming other factors are held constant. A significant increase in prevailing interest rates that results in a substantial increase in the interest rates applicable to our indebtedness could substantially increase our interest expense and have a material adverse effect on our financial condition, results of operations, and cash flows.

Increases in interest rates could adversely impact our ability to incur indebtedness for acquisitions or other purposes.

We have historically incurred indebtedness to fund our acquisitions and other working capital needs. Interest rates may increase in the future and, as a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. A rising interest rate environment could have an adverse impact, as a result of such increased financing costs, on our ability to incur indebtedness for acquisitions or other purposes.

We may be unable to successfully identify, execute, or effectively integrate future acquisitions, which may negatively affect our results of operations.

We will continue to pursue acquisitions in the future. Although we regularly engage in discussions with, and submit proposals to, acquisition candidates, suitable acquisitions may not be available in the future on reasonable terms. If we do identify an appropriate acquisition candidate, we may be unable to successfully negotiate the terms of an acquisition, finance the acquisition, or, if the acquisition occurs, effectively integrate the acquired business into our existing businesses. Negotiations of potential acquisitions and the integration of acquired business operations may require a disproportionate amount of management's attention and our resources. Even if we complete additional acquisitions, continued acquisition financing may not be available or available on reasonable terms, any new businesses may not generate the anticipated level of revenues, the anticipated cost efficiencies, or synergies may not be realized, and these businesses may not be integrated successfully or operated profitably. Our inability to successfully identify, execute, or effectively integrate future acquisitions may negatively affect our results of operations.

We may be unable to compete effectively with larger companies for acquisitions, which could have a material adverse effect on our businesses, results of operations, and financial condition.

The industries in which we operate are intensely competitive and we compete with other companies that have greater resources than we have. Our ability to acquire additional businesses or properties in the future will be dependent upon our ability to evaluate and select suitable businesses or properties for acquisition and to consummate transactions in a highly competitive environment. Many of our larger competitors have refining operations, market petroleum, and other products and explore for and produce natural gas and crude oil on a regional, national, or worldwide basis. These companies may be able to pay more for acquisition targets, or evaluate or bid for and purchase a greater number of acquisition targets, than our resources permit. Our inability to compete effectively with larger companies for acquisitions could have a material adverse effect on our business, financial condition, and results of operations.

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating potential liabilities.

Our recent growth is due in large part to acquisitions, such as the acquisitions of PHR, Mid Pac, and Wyoming Refining . We expect acquisitions to be instrumental to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of potential unknown and contingent liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform due diligence reviews of acquired businesses and assets that we believe are generally consistent with industry practices. However, such reviews will not reveal all existing or potential problems. In addition, our reviews may not permit us to become sufficiently familiar with potential environmental problems or other contingent and unknown liabilities that may exist or arise. As a result, there may be unknown and contingent liabilities related to acquired businesses and assets of which we are unaware. We could be liable for unknown obligations relating to acquisitions for which indemnification is not available, which could materially adversely affect our business, results of operations, and cash flows.

Both of our refineries are scheduled for maintenance turnarounds in the next few years that will involve significant expenditures.

Wyoming Refining expects to perform a significant maintenance turnaround during 2019 and 2020 and our refinery in Hawaii is scheduled to undergo a significant maintenance turnaround between 2019 and 2020. During a turnaround, all or a portion of each refinery's production may be halted or disrupted. Any turnaround, if unsuccessful or delayed, could have a material adverse effect on our business, financial condition, or results of operations.

In addition, both of our refineries may require additional unscheduled down time for unanticipated maintenance or repairs that are more frequent than our scheduled turnarounds. Refinery operations may also be disrupted by external factors such as a suspension of feedstock deliveries or an interruption of electricity, natural gas, water treatment, or other utilities. Other potentially disruptive factors include natural disasters, severe weather conditions, workplace or environmental accidents, interruptions of supply, work stoppages, losses of permits or authorizations, or acts of terrorism. Disruptions to our refining operations could reduce our revenues during the period of time that our processing units are not operating.

The pending CHS Acquisition may not close as anticipated.

The CHS Acquisition is expected to close in the first quarter of 2018, subject to the satisfaction of certain customary closing conditions. If these conditions are not satisfied or waived, the CHS Acquisition will not be consummated. Certain of the conditions that remain to be satisfied include, but are not limited to:

- the continued accuracy of the representations and warranties contained in the CHS Acquisition Agreement ;
- the performance by each party of its obligations under the CHS Acquisition Agreement ;
- the absence of any decree, order, injunction, ruling, or judgment that prohibits the CHS Acquisition or makes the CHS Acquisition unlawful;

- the obtaining of certain third-party consents required for the consummation of the CHS Acquisition ;
- the absence of a material adverse effect on the CHS Station Properties ; and
- the execution of certain agreements related to the consummation of the CHS Acquisition .

In addition, we and CHS Inc. can mutually agree to terminate the CHS Acquisition Agreement without completing the CHS Acquisition . Further, we or CHS Inc. can unilaterally terminate the CHS Acquisition Agreement without the other party's agreement and without completing the CHS Acquisition upon the occurrence of certain events.

The CHS Acquisition Agreement further provides that in certain events some of the retail gasoline and convenience store facilities that are subject to the CHS Acquisition Agreement will be excluded from the CHS Station Properties . If any such events occur, it is possible that the CHS Acquisition will close but that we will acquire fewer CHS Station Properties than we anticipated upon entry into the CHS Acquisition Agreement , which could have an adverse effect on our ability to realize all of the expected benefits of the CHS Acquisition .

We cannot assure you that the pending CHS Acquisition will close on our expected timeframe, or at all, or close without material adjustment.

We may fail to successfully integrate the CHS Station Properties with our existing business in a timely manner, which could have a material adverse effect on our business, financial condition, results of operations, or cash flows, or fail to realize all of the expected benefits of the CHS Acquisition , which could negatively impact our future results of operations.

Integration of the CHS Station Properties with our existing business will be a complex, time-consuming, and costly process, particularly given that the CHS Acquisition will diversify the geographic areas in which we operate. A failure to successfully integrate the CHS Station Properties with our existing business in a timely manner may have a material adverse effect on our business, financial condition, results of operations, or cash flows. The difficulties of combining the acquired retail properties include, among other things:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the acquired assets and operations;
- the diversion of management's attention from other business concerns;
- integrating personnel from diverse business backgrounds and organizational cultures;
- managing relationships with new customers and suppliers for whom we have not previously provided products or services;
- an inability to complete other internal growth projects and/or acquisitions;
- difficulties integrating new technology systems that we have not historically used in our operations or financial reporting;
- potential environmental or regulatory compliance matters or liabilities;
- coordinating geographically disparate organizations, systems, and facilities; and
- coordinating and consolidating corporate and administrative functions.

If we consummate the CHS Acquisition and if any of these risks or unanticipated liabilities or costs were to materialize, then any desired benefits of the CHS Station Properties may not be fully realized, if at all, and our future results of operations could be negatively impacted. In addition, the CHS Station Properties may actually perform at levels below the forecasts we used to evaluate the CHS Station Properties , due to factors that are beyond our control. If the CHS Station Properties perform at levels below the forecasts we used to evaluate the CHS Station Properties , then our future results of operations could be negatively impacted.

Flaws in our ongoing due diligence in connection with the CHS Acquisition could have a significant negative effect on our financial condition and results of operations.

We conducted limited due diligence in connection with the CHS Acquisition prior to signing the CHS Acquisition Agreement and are continuing to conduct due diligence during the period between the signing and closing of the CHS Acquisition . Intensive due diligence is time consuming and expensive due to the operations, accounting, finance, and legal professionals who must be involved in the due diligence process and the fact that such efforts do not always lead to a consummated transaction. Diligence may not reveal all material issues that may affect a particular CHS Station Property. In addition, factors outside of our control may later arise. If, during the diligence process, we fail to identify issues specific to a CHS Station Property or its operations, we may be forced to later write down or write off assets, restructure our operations, or incur impairment or other charges that could result in other reporting losses. In addition, charges of this nature may cause us to violate net worth or other covenants to which we may become subject if we obtain debt financing. We cannot assure you that we will not have to take write-downs or write-offs in connection with the acquisitions of certain of the assets and assumption of certain liabilities of the CHS Station Properties , which could have a negative effect on our financial condition and results of operation following closing.

If our goodwill or intangible assets become impaired, we may be required to record a significant charge to earnings.

Under GAAP, we review our intangible assets for impairment when events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill is required to be tested for impairment at least annually. Factors that may be considered when determining if the carrying value of our goodwill or intangible assets may not be recoverable include a significant decline in our expected future cash flows or a sustained, significant decline in our stock price and market capitalization.

As a result of our acquisitions, we have significant goodwill and intangible assets recorded on our balance sheet. In addition, significant negative industry or economic trends, such as those that have occurred as a result of the recent economic downturn, including reduced estimates of future cash flows or disruptions to our business could indicate that goodwill or intangible assets might be impaired. If, in any period, our stock price decreases to the point where our market capitalization is less than our book value, this too could indicate a potential impairment and we may be required to record an impairment charge in that period. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on projections of future operating performance. We operate in highly competitive environments and projections of future operating results and cash flows may vary significantly from actual results. As a result, we may incur substantial impairment charges to earnings in our financial statements should an impairment of our goodwill or intangible assets be determined resulting in an adverse impact on our results of operations.

A substantial portion of our refining workforce is unionized and we may face labor disruptions that would interfere with our operations.

As of December 31, 2017 , we employed approximately 905 people, with a collective bargaining agreement covering 149 of those employees. The union ratified a four-year extension of the collective bargaining agreement on March 23, 2015. On January 13, 2016, a claim against us was brought to the NLRB alleging a refusal to bargain collectively and in good faith. Accordingly, we may not be able to prevent a strike or work stoppage in the future and any such work stoppage could cause disruptions in our business and have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our disclosure controls and procedures may not prevent or detect all acts of fraud.

Our disclosure controls and procedures are designed to reasonably assure that information required to be disclosed by us in reports we file or submit under the Exchange Act is accumulated and communicated to management, recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms.

Our management, including our Chief Executive Officer and Chief Financial Officer, believes that any disclosure controls and procedures or internal controls and procedures, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, they cannot provide absolute assurance that all control issues and instances of fraud, if any, within our companies have been prevented or detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by an unauthorized override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events and we cannot assure you that any design will succeed in achieving its stated goals under all potential future conditions. Accordingly, because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and may not be detected.

Adverse changes in global economic conditions and the demand for transportation fuels may impact our business and financial condition in ways that we currently cannot predict.

The economic recovery from the recent recession continues to be tenuous and the risk of further significant global economic downturn remains. Further prolonged downturns or failure to recover could result in declines in consumer and business confidence and spending as well as increased unemployment and reduced demand for transportation fuels. This would adversely affect the business and economic environment in which we operate. These conditions increase the risks associated with the creditworthiness of our suppliers, customers, and business partners. The consequences of such adverse effects could include interruptions or delays in our suppliers' performance of our contracts, reductions and delays in customer purchases, delays in or the inability of customers to obtain financing to purchase our products, and bankruptcy of customers. Any of these events may adversely affect our financial condition, cash flows, and profitability.

Adverse results of legal proceedings could materially adversely affect us.

We may be subject to a variety of legal proceedings and claims that arise out of the ordinary conduct of our business. Results of legal proceedings cannot be predicted with certainty. Regardless of its merits, litigation may be both lengthy and disruptive to the company’s operations and may cause significant expenditures and diversion of management attention. We may be faced with significant monetary damages or injunctive relief that could materially adversely affect our business operations or materially and adversely affect our financial position and results of operations should we fail to prevail in certain matters.

Competition from integrated national and international oil companies that produce their own supply of feedstocks, from importers of refined products, and from high volume retailers and large convenience store retailing operators who may have greater financial resources, could materially affect our business, financial condition, and results of operations.

We compete with a number of integrated national and international oil companies who produce crude oil, some of which is used in their refining operations. Unlike these oil companies, we must purchase all of our crude oil from unaffiliated sources. Because these oil companies benefit from increased commodity prices, have greater access to capital, and have stronger capital structures, they are able to better withstand poor and volatile market conditions, such as a lower refining margin environment, shortages of crude oil and other feedstocks, or extreme price fluctuations.

We face strong competition in the fuel and convenience store retailing market for the sale of retail gasoline and convenience store merchandise. Our competitors include service stations operated by integrated major oil companies and well-recognized national high-volume retailers and regional large chain convenience store operators, often selling gasoline or merchandise at aggressively competitive prices.

Some of these competitors may have access to greater financial resources, which may provide them with a better ability to bear the economic risks inherent in all phases of our industry. Fundamental changes in the supply dynamics of foreign product imports could lead to reduced margins for the refined products we market, which could have an adverse effect on the profitability of our business.

Tesoro has disputed our calculation of the 2015 and 2016 earn-out amounts with respect to our acquisition of PHR and it is possible that we may be required to pay Tesoro additional amounts for such periods.

The contingent earn-out payments with respect to our acquisition of PHR from Tesoro are calculated annually for each of the years ended 2014, 2015, and 2016 with an annual limit of $20 million and an overall limit of $40 million . During 2016, we paid Tesoro a total of $16.8 million to settle the 2014 and 2015 earn-out periods. Tesoro has disputed our calculation of the 2015 and 2016 earn-out periods and has asserted that it is entitled to an additional earn-out amount of $4.3 million for the 2015 earn-out period and a total earn-out amount of $8.3 million for the 2016 earn-out period. If we and Tesoro are unable to agree on the calculation of the 2015 and 2016 earn-out amounts, the dispute will be resolved in accordance with the dispute resolution provisions set forth in the membership interest purchase agreement to determine the amounts owed, if any. It is possible that we may be required to pay Tesoro additional amounts for the disputed earn-out periods, subject to the annual and overall limits.

RISKS RELATED TO OUR COMMON STOCK

Because we have no near term plans to pay cash dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We have never declared or paid any cash dividends on our common stock. We currently intend to retain all available funds and any future earnings for use in the operation and expansion of our business and do not anticipate declaring or paying any cash dividends on our common stock in the near term. Any future determination as to the declaration and payment of cash dividends will be at the discretion of our board of directors and will depend on then-existing conditions, including our financial condition, results of operations, contractual restrictions, capital requirements, business prospects, and other factors that our board of directors considers relevant.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock, or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

The price of our common stock historically has been volatile. This volatility may affect the price at which you could sell your common stock.

The market price for our common stock has varied between a high of $21.94 on September 29, 2017 , and a low of $12.96 on January 11, 2017 , during the year ended December 31, 2017 . This volatility may affect the price at which you could sell your common stock. Our stock price is likely to continue to be volatile and subject to significant price and volume fluctuations in response to market and other factors; variations in our quarterly operating results from our expectations or those of securities analysts or investors; downward revisions in securities analysts' estimates; and announcement by us or our competitors of significant acquisitions, strategic partnerships, joint ventures, or capital commitments.

The market for our common stock has been historically illiquid, which may affect your ability to sell your shares.

The volume of trading in our common stock has historically been low. In addition, a substantial amount of our common stock is held by two investors who have restrictions on their ability to sell the stock. The lack of substantial liquidity can adversely affect the price of our stock at a time when you might want to sell your shares. There is no guarantee that an active trading market for our common stock will develop or be maintained on the NYSE, or that the volume of trading will be sufficient to allow for timely trades. Investors may not be able to sell their shares quickly or at the latest market price if trading in our stock is not active or if trading volume is limited. In addition, if trading volume in our common stock is limited, trades of relatively small numbers of shares may have a disproportionate effect on the market price of our common stock.

Delaware law, our charter documents, and concentrated stock ownership may impede or discourage a takeover, which could reduce the market price of our common stock.

We are a Delaware corporation and the anti-takeover provisions of Delaware law impose various impediments to the ability of a third party to acquire control of us, even if a change in control would be beneficial to our existing stockholders. For example, the change in ownership limitations contained in Article 11 of our certificate of incorporation could have the effect of discouraging or impeding an unsolicited takeover proposal. In addition, our board of directors or a committee thereof has the power, without stockholder approval, to designate the terms of one or more series of preferred stock and issue shares of preferred stock. The ability of our board of directors or a committee thereof to create and issue a new series of preferred stock and certain provisions of Delaware law and our certificate of incorporation and bylaws could impede a merger, takeover, or other business combination involving us or discourage a potential acquirer from making a tender offer for our common stock, which, under certain circumstances, could reduce the market price of our common stock.

Zell Credit Opportunities Master Fund, L.P. ("ZCOF") and Whitebox Advisors, LLC ("Whitebox"), together with their respective affiliates, each own or have the right to acquire as of March 7, 2018 approximately 28.1% and 9.6%, respectively, of our outstanding common stock. The level of their combined ownership of shares of our common stock could have the effect of discouraging or impeding an unsolicited acquisition proposal.

We may issue preferred stock with terms that could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations, and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could adversely affect the residual value of the common stock.

We may issue shares of common stock in satisfaction of general unsecured claims from our predecessor's bankruptcy that would dilute your ownership of our common stock.

In December 2011 and January 2012, Delta and its subsidiaries filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware, and in March 2012, obtained approval from the bankruptcy court to proceed with a plan of reorganization. Pursuant to this plan, among other things, certain allowed general unsecured claims may be paid with shares of our common stock. As of December 31, 2017 , two claims totaling approximately $22.4 million remain to be resolved and we have reserved approximately $0.5 million representing the estimated value of claims remaining to be settled which are deemed probable and estimable at period end. The settlement of claims is subject to ongoing litigation and we are unable to predict with certainty how many shares will be required to satisfy all claims. Pursuant to the plan of reorganization, allowed claims are settled at a ratio of 54.4 shares per $1,000 of claim. Any issuances by us of common stock to satisfy claims would have a dilutive impact on the ownership interest of existing common stockholders and could cause the market price of our common stock to decline.

Future sales of our common stock could reduce our stock price and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We are not restricted from issuing additional shares of common stock, including shares issuable pursuant to securities that are convertible into or exchangeable for, or that represent the right to receive, common stock. We have approximately 46.3 million shares of common stock outstanding as of March 7, 2018 .

Subject to the satisfaction of vesting conditions and the requirements of Rule 144 of the Securities Act, shares of our common stock registered under our equity incentive plan are available for resale immediately in the public market without restriction. In addition, subject to the change in ownership limitations contained in Article 11 of our certificate of incorporation, up to 7,722,809 shares of our common stock registered under our registration statements on Form S-3, declared effective on November 30, 2016 and December 21, 2016, are available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into or exchangeable for, or that represent the right to receive, common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company has unresolved comments from the staff of the Securities and Exchange Commission with respect to its Form 10-K for its fiscal year ended December 31, 2016. The comments relate to the proved undeveloped reserves that we own indirectly through our investment in Laramie Energy and, in general, request explanations and supporting detail about the scheduling and reporting of such proved undeveloped reserves and changes to such proved undeveloped reserves year-to-year. In our responses, we have presented detailed explanations about the process we follow to ensure that our estimates of proved undeveloped reserves comply with the requirements of Regulation S-X, and we have provided detailed information explaining changes in our proved undeveloped reserves from year-to-year (e.g., adds, conversions, revisions and transfers).

Item 2. PROPERTIES

Please read " Item 1. — Business " of this Form 10-K for the location and general character of the properties used in our refining, retail, and logistics segments. Our corporate headquarters are located at 800 Gessner Road, Suite 875, Houston, Texas, 77024. We believe that these properties and facilities are adequate for our operations and are maintained in a good state of repair.

Natural Gas and Oil Properties

Laramie Energy

All of the assets held by Laramie Energy are located in Garfield, Mesa, and Rio Blanco Counties, Colorado. All of the natural gas and crude oil reserves associated with such assets are produced primarily from the Mesaverde Formation and to a lesser extent the Mancos Formation and some of the acreage is contiguous. The geology of the Piceance Basin is characterized as highly consistent and predictable over large areas, which generally equates to reliable timing and cost expectations during drilling and completion activities, as well as minimal well-to-well variance in production and reserves when completed with the same methodology. Laramie Energy considers the Mesaverde Formation within Garfield, Mesa, and Rio Blanco Counties, Colorado, to be a single field. Laramie Energy and its predecessor company have drilled over 300 natural gas wells with over a 99% success rate in the Piceance Basin.

Other

We have a 3.3% to 4.5% working interest in 22 wells in the southern region of the Piceance Basin. These wells are operated by Caerus Oil & Gas. We also have overriding royalty interests in 12 wells located in Eddy County, New Mexico. Our interest in these wells varies from 0.32% to 2.5%. These wells are operated by Mewbourne Oil Company. On March 23, 2016, we entered into a settlement agreement with Whiting Oil and Gas Corporation ("Whiting"), whereby we paid Whiting an aggregate of $3.9 million to transfer the entirety of our interest in the Point Arguello Unit offshore California ("Point Arguello") to Whiting and to satisfy any and all obligations in respect of such interest in Point Arguello.

Reserves

For a table presenting the estimated natural gas and crude oil reserves we own indirectly through Laramie Energy , please read “ Item 1. — Business — Other Operations ” of this Form 10-K. The natural gas and crude oil reserves we own directly are not material.

Internal Controls Over Reserve Estimates, Technical Qualifications, and Technologies Used

Our policies regarding internal controls over reserve estimates require reserves to be in compliance with the SEC definitions and guidance and for all reserve estimates to be prepared by an independent third-party reserve engineering firm and reviewed by our reserves committee, which includes certain members of senior management. In addition, with respect to the reserves that we own indirectly through Laramie Energy , we participate in Laramie Energy 's quarterly board meetings and review Laramie Energy 's development plan and related capital expenditures in connection with our review of the development and classification of such reserves. As we do not operate our interests in our natural gas and crude oil assets, we do not have an internal reserve engineering staff and do not prepare any internal reserve estimates. William Monteleone, our Chief Financial Officer and the chair of the reserves committee, reviews the independence and professional qualifications of the third-party engineering firms we engage. He also supervises the submission of technical and financial data to third-party engineering firms and reviews the prepared reports with the other members of the reserves committee. Mr. Monteleone has more than nine years of experience in senior financial positions in the oil and gas industry. The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (“NSAI”), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Benjamin W. Johnson and Mr. John G. Hattner. Mr. Johnson, a Licensed Professional Engineer in the State of Texas (No. 124738), has been practicing consulting petroleum engineering at NSAI since 2007 and has over two years of prior industry experience. He graduated from Texas Tech University in 2005 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Hattner, a Licensed Professional Geoscientist in the State of Texas, Geophysics (License No. 559), has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 11 years of prior industry experience. He graduated from University of Miami, Florida, in 1976 with a Bachelor of Science Degree in Geology; from Florida State University in 1980 with a Master of Science Degree in Geological Oceanography; and from Saint Mary’s College of California in 1989 with a Master of Business Administration Degree. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The professional qualifications of the individuals at NSAI who were responsible for overseeing the preparation of our reserve estimates as of December 31, 2017 have been filed as part of Exhibit 99.1 to this Annual Report on Form 10-K.

A variety of methodologies were used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, analog type curve analysis, log analysis, and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

Production Volumes, Unit Prices and Costs

All of Laramie Energy's properties are located in Garfield, Mesa, and Rio Blanco Counties, Colorado. Over 95% of Laramie Energy's total estimated proved reserves are located in the same geological formation, the Mesaverde Formation, which Laramie Energy considers to be a single field.

The following table sets forth certain information regarding volumes of production sold and average prices received associated with our share of Laramie Energy's production and sales of natural gas and crude oil for the years ended December 31, 2017 , 2016 , and 2015 .

	Year Ended December 31,		
Company's share of Laramie Energy:	**2017**	**2016**	**2015**
Production volumes:			
Oil (Mbbls)	71	59	20
NGLs (Mbbls)	608	552	149
Natural Gas (MMcf)	18,104	15,192	4,745
Total (MMcfe)	22,178	18,858	5,759
Net average daily production:			
Oil (Bbls)	190	160	55
NGLs (Bbls)	1,662	1,508	408
Natural Gas (Mcf)	49,460	41,509	13,000
Average sales price:			
Oil (Per Bbl)	$ 45.61	$ 37.85	$ 38.46
NGLs (Per Bbl)	20.02	11.61	11.76
Natural Gas (per Mcf)	2.81	2.30	2.47
Hedge gain (loss) (per Mcfe)	(1.25)	(1.47)	0.33
Lease operating costs (per Mcfe)	0.49	0.45	0.56

The table above excludes production volumes related to our other non-operated natural gas and oil interests of 59 MMcfe , 66 MMcfe , and 311 MMcfe for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Please read Note 23—Supplemental Oil and Gas Disclosures (Unaudited) to our consolidated financial statements under Item 8 of this Form 10-K for further information on our proved reserves related to our other non-operated natural gas and oil interests.

Proved Undeveloped Reserves

All of our proved undeveloped reserves at December 31, 2017 are held through our minority equity ownership in Laramie Energy . The following table provides information regarding changes in our share of Laramie Energy 's proved undeveloped reserves for the year ended December 31, 2017 .

	Gas (MMcf)	Oil (Mbbl)	NGLs (Mbbl)	Total (MMcfe)
Proved undeveloped reserves at December 31, 2016 (1)	150,302	451	4,195	178,181
Revisions of previous estimates	(13,152)	55 —	(732)	(17,216)
Extensions and discoveries	—	—	—	—
Acquisitions	—	—	—	—
Conversion to proved developed reserves	(18,572)	(57)	(550)	(22,215)
Proved undeveloped reserves at December 31, 2017	118,578	449	2,913	138,750

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(1) We have revised our previously disclosed proved undeveloped reserves quantities as of December 31, 2016 to reflect the removal of Laramie Energy's proved undeveloped locations scheduled for completion more than 5 years from initial booking that were classified as proved undeveloped reserves as of December 31, 2016. For additional information, please read Note 23—Supplemental Oil and Gas Disclosures (Unaudited) to our consolidated financial statements under Item 8 of this Form 10-K.

As of December 31, 2017 , our share of Laramie Energy ’s proved undeveloped reserves totaled 138,750 MMcfe, an approximate 22% decrease from proved undeveloped reserves at December 31, 2016 . The decrease in our share of Laramie Energy’s proved undeveloped reserves was due to the following:

- During the year ended December 31, 2017, Laramie Energy expended approximately $23.3 million in connection with the development of its proved undeveloped reserves to convert 30 locations to proved developed reserves. Our share of Laramie's proved undeveloped reserves converted to proved developed reserves during 2017 was 22,215 MMcfe. The total number of proved undeveloped locations converted to proved developed reserves during 2017 was consistent with Laramie Energy's original development plan (the "2017 development plan"). Of the 30 locations converted to proved developed locations in 2017, only 9 were originally scheduled to be completed in 2017. In January 2017, Laramie Energy renegotiated its gathering and processing contract with its primary gathering and processing counterparty (the "Gathering Contract") and modified its development schedule to take advantage of cost reductions with respect to certain locations covered by the Gathering Contract. During 2017, Laramie Energy converted 30,362 MMcfe of probable reserves from 44 locations to proved developed reserves. Laramie Energy added these locations to the 2017 development schedule because they are covered by the Gathering Contract.
- In recognition of Laramie's historically low conversion rate, the potential impact of recent commodity price volatility and Par's position as an equity interest owner without control of Laramie Energy's operations, Par has decided to base its determination of Laramie Energy's proved undeveloped reserves at year end 2017 on only a two year drilling and three year completion time horizon. The negative revisions of 17,216 MMcfe to our share of Laramie Energy's proved undeveloped reserves during 2017 are primarily related to the change in Par's booking policy.

Laramie Energy expects to expend approximately $101.8 million and $73.1 million to convert approximately 122 and 60 proved undeveloped locations to proved developed reserves in 2018 and 2019, respectively. Through March 6, 2018 Laramie Energy had already drilled 25 and completed 22 of the proved undeveloped locations included in the 2017 reserve report.

Laramie Energy is currently running two drilling rigs performing multi-well pad drilling in the Mesaverde Formation. The rigs are expected to drill a mix of both proved undeveloped and probable reserves locations in a program or "manufacturing" style process. During 2017, drill times averaged 4.9 days per well, or 6.3 wells per month, and the typical pad contained 16-24 wells.

As of December 31, 2017 , Laramie Energy had no proved undeveloped reserves that are expected to remain undeveloped for five years or more after booking as proved reserves.

Productive Wells and Acreage

The table below shows, as of December 31, 2017 , our share of Laramie Energy's gross and net wells and developed acres. Developed acreage consists of acres spaced or assignable to productive wells.

	Productive Wells					
	Oil		Gas (1)		Developed Acres	
Location	**Gross (2)**	**Net (3)**	**Gross (2)**	**Net (3)**	**Gross (2)**	**Net (3)**
Colorado (4)	—	—	1,762	745	20,642	7,019

(1) Some of the wells classified as "gas" wells also produce minor amounts of crude oil.

(2) A "gross well" or "gross acre" is a well or acre in which a working interest is held. The number of gross wells or acres is the total number of wells or acres in which a working interest is owned.

(3) A "net well" or "net acre" is deemed to exist when the sum of fractional ownership interests in gross wells or acres equals one. The number of net wells or net acres is the sum of the fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions thereof.

(4) Net wells and net developed acres are reflected as if we owned our interest directly.

As of December 31, 2017 , we also held interests in one productive gas well and 20 developed acres related to our other non-operated natural gas interests.

Undeveloped Acreage

At December 31, 2017 , our share of undeveloped acreage held through our ownership in Laramie Energy is set forth below:

	Undeveloped Acres (1) (2)	
Location	**Gross**	**Net**
Colorado (3)	240,382	54,073

(1) Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and gas, regardless of whether such acreage contains proved reserves.

(2) There are no material near-term lease expirations for which the carrying value at December 31, 2017 has not already been impaired in consideration of these expirations or capital budgeted to convert acreage to held by production.

(3) Net undeveloped acres are reflected as if we owned our interest directly.

Drilling Activity

Laramie Energy completed 74 natural gas wells during the year ended December 31, 2017 that were drilled during 2017 and prior years. Laramie Energy drilled no exploratory wells and 124 development wells during 2017. As of December 31, 2017, Laramie Energy had drilled but not completed 59 natural gas development wells.

During 2016 , Laramie Energy completed 56 natural gas wells that were drilled during 2016 and prior years. During 2015 , Laramie Energy completed 24 natural gas wells that were drilled during 2015 and prior years. The operators of our other natural gas and oil interests in Colorado and New Mexico did not drill any exploratory or development wells during 2017 , 2016 , and 2015 .

Delivery Commitments

Our natural gas and oil operations had no material delivery commitments as of December 31, 2017 .

Item 3. LEGAL PROCEEDINGS

PHMSA Matters

In 2016, PHMSA conducted an integrated inspection of the Wyoming refinery's products pipeline. Due to compliance violations identified during the inspection, the Wyoming refinery was assessed a civil penalty of $279 thousand in December 2017, which we paid in January 2018.

Consent Decree

On July 18, 2016, PHR and subsidiaries of Tesoro entered into a consent decree with the EPA, the DOJ, and other state governmental authorities concerning alleged violations of the federal CAA related to the ownership and operation of multiple facilities owned or formerly owned by Tesoro and its affiliates, including our Hawaii refinery. As a result of the Consent Decree, PHR expanded its previously-announced 2016 Hawaii refinery turnaround to undertake additional capital improvements to reduce emissions of air pollutants and to provide for certain NOx and SO_2 emission controls and monitoring required by the Consent Decree. Although the turnaround was completed in the third quarter of 2016, work related to the Consent Decree is ongoing. We estimate the cost of compliance with the Consent Decree to be approximately $30 million . However, Tesoro is responsible under the Environmental Agreement for directly paying, or reimbursing PHR , for all reasonable third-party capital expenditures incurred for the Consent Decree to the extent related to acts or omissions prior to the date of the closing of the PHR acquisition. Tesoro is obligated to pay all applicable fines and penalties related to the Consent Decree.

Other

From time to time, we may be involved in other litigation relating to claims arising out of our operations in the normal course of our business. As of the date of this Annual Report on Form 10-K, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations, or cash flows. Any litigation pending at the time we emerged from Chapter 11 was transferred to the General Trust for resolution and settlement. For more information, please read " Item 1. — Business —Bankruptcy and Plan of Reorganization – General Recovery Trust" and Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 of this Form 10-K **.**

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

Market Information

On February 20, 2018, our common stock began trading on the NYSE under the symbol "PARR." Prior to that date, our common stock was traded on the NYSE American under the symbol "PARR". The high and low sale prices for our common stock for the most recent two fiscal years are shown in the table below.

Quarter Ended	High	Low
2017		
December 31, 2017	$21.86	$18.63
September 30, 2017	$21.94	$15.90
June 30, 2017	$18.08	$16.01
March 31, 2017	$16.49	$12.96
2016		
December 31, 2016	$15.46	$12.47
September 30, 2016	$16.00	$12.18
June 30, 2016	$20.00	$13.90
March 31, 2016	$24.11	$17.48

As of March 7, 2018 , there were 276 common stockholders of record. On March 7, 2018 , the closing price of our common stock was $17.93 per share on the NYSE.

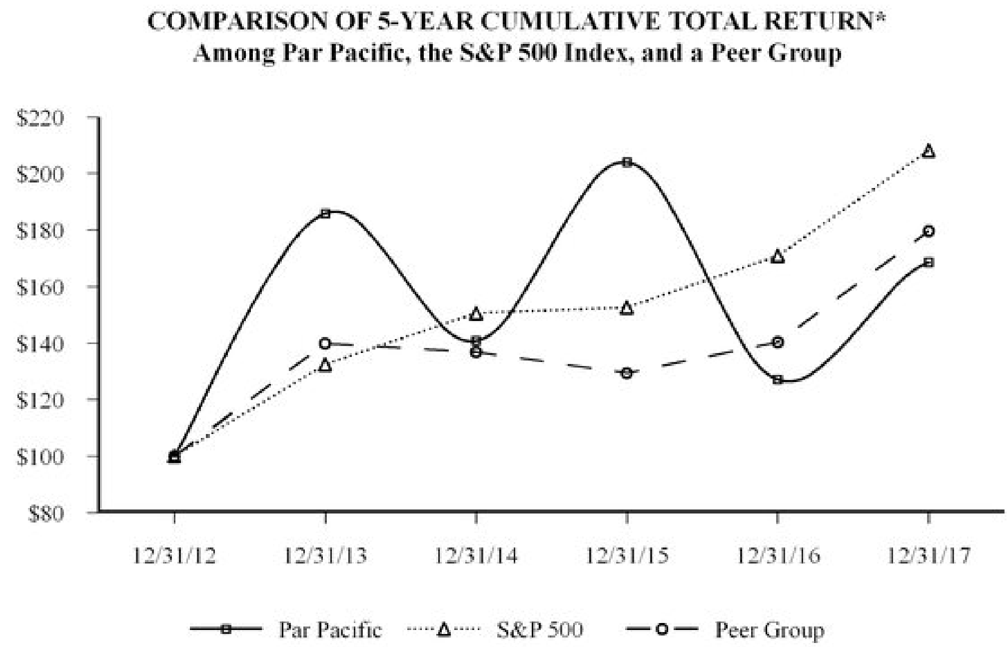
Dividends

We have not paid dividends on our common stock and we do not expect to do so in the foreseeable future. In addition, under the ABL Credit Facility and the indenture governing the 7.75% Senior Secured Notes , our subsidiaries are restricted from paying dividends or making other equity distributions, subject to certain exceptions. For more information, please read Note 11— Debt to our consolidated financial statements under Item 8 of this Form 10-K.

Stock Performance Graph

The following performance graph and related information shall not be deemed "soliciting material" or "filed" with the SEC, nor shall such information be deemed to be incorporated by reference into any future filings under the Securities Act of 1933 or the Securities Exchange Act of 1934, each as amended.

This performance graph and the related textual information are based on historical data and are not indicative of future performance. The following line graph compares the cumulative total return on an investment in our common stock against the cumulative total return of the S&P 500 Composite Index and an index of peer companies (that we selected) for the five fiscal years ended December 31, 2017 . The performance graph of our peer group is weighted by market value at the beginning of the period and our peer group consists of the following companies: Calumet Specialty Products Partners, L.P., Casey's General Stores, Inc., CVR Energy, Inc., Darling Ingredients Inc., Delek US Holdings, Inc., FutureFuel Corp., Green Plains Inc., Macquarie Infrastructure Corporation, Methanex Corporation, Pacific Ethanol, Inc., Renewable Energy Group, Inc., REX American Resources Corporation, SEACOR Holdings Inc., Stepan Company, and Westlake Chemical Corporation. Alon USA Energy, Inc. was excluded from our peer group because it was acquired by Delek US Holdings, Inc. We believe our peer group, which is made up of oil and gas refining and marketing companies, retailers, and companies that are generally similar to our operating segments, provides for meaningful comparability to our business as a whole.



*$100 invested on December 31, 2012 in stock or index, including reinvestment of dividends.

Recent Sales of Unregistered Securities

During the year ended December 31, 2017 , we did not have any sales of securities in transactions that were not registered under the Securities Act that have not been reported in a Form 8-K or Form 10-Q.

Issuer Purchases of Equity Securities

The following table sets forth certain information with respect to repurchases of our common stock during the quarter ended December 31, 2017 :

Period	Total number of shares (or units) purchased (1)	Average price paid per share (or unit)	Total number of shares (or units) purchased as part of publicly announced plans or programs	Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 1 - October 31, 2017	137	$ 20.79	—	—
November 1 - November 30, 2017	530	19.51	—	—
December 1 - December 31, 2017	1,732	19.77	—	—
Total	2,399	$ 19.77	—	—

(1) All shares repurchased were surrendered by employees to pay taxes withheld upon the vesting of restricted stock awards.

Item 6. SELECTED FINANCIAL DATA

The selected financial information presented below as of December 31, 2017 and 2016 and for the years ended December 31, 2017 , 2016 , and 2015 was derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The selected financial information presented below as of December 31, 2015 , 2014 , and 2013 and for the years ended December 31, 2014 and 2013 was derived from our audited consolidated financial statements not included in this Annual Report on Form 10-K. The selected financial information should be read in conjunction with the consolidated financial statements and related notes and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
(in thousands, except per share data)	**2017**	**2016 (1)**	**2015 (2)**	**2014**	**2013 (3)**
Statement of Operations Data:					
Revenues	$ 2,443,066	$ 1,865,045	$ 2,066,337	$ 3,108,025	$ 886,014
Depreciation, depletion and amortization	45,989	31,617	19,918	14,897	5,982
Impairment expense	—	—	9,639	—	—
Trust litigation and settlements	—	—	—	—	6,206
Operating income (loss)	93,958	(16,494)	61,514	(37,532)	(47,405)
Interest expense and financing costs, net	(31,632)	(28,506)	(20,156)	(17,995)	(13,285)
Loss on termination of financing agreements	(8,633)	—	(19,669)	(1,788)	(6,141)
Change in value of common stock warrants	(1,674)	2,962	(3,664)	4,433	(10,159)
Change in value of contingent consideration	—	10,770	(18,450)	2,849	—
Equity earnings (losses) from Laramie Energy, LLC	18,369	(22,381)	(55,983)	2,849	(2,941)
Net income (loss)	72,621	(45,835)	(39,911)	(47,041)	(79,173)
Income (loss) per diluted common share	1.58	(1.08)	(1.06)	(1.44)	(4.01)
Balance Sheet Data:					
Cash and cash equivalents	$ 118,333	$ 47,772	$ 167,788	$ 89,210	$ 38,061
Total current assets	603,544	403,108	531,752	460,789	544,501
Total assets	1,347,407	1,145,433	892,261	735,236	813,213
Total current liabilities	470,952	382,765	365,040	310,806	453,388
Total long-term debt, net of current maturities	384,812	350,110	154,212	101,739	79,872
Total liabilities	899,688	776,524	551,650	443,077	584,949
Total stockholders' equity	447,719	368,909	340,611	292,159	228,264

(1) We completed the WRC Acquisition effective July 14, 2016 , therefore, the results of WRC are only included subsequent to July 14, 2016 . Please read Note 4—Acquisitions to the consolidated financial statements under Item 8 of this Form 10-K for further information.
(2) We completed the acquisition of Mid Pac effective April 1, 2015, therefore, the results of Mid Pac are only included subsequent to April 1, 2015. Please read Note 4—Acquisitions to the consolidated financial statements under Item 8 of this Form 10-K for further information.
(3) We completed the acquisition of PHR effective September 25, 2013, therefore, the results of PHR are only included subsequent to September 25, 2013.

Item 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are a growth-oriented company based in Houston, Texas, that manages and maintains interests in energy and infrastructure businesses. We were created through the successful reorganization of Delta Petroleum Corporation (“Delta”) in August 2012. The reorganization converted approximately $ 265 million of unsecured debt to equity and allowed us to preserve significant tax attributes. For more information, please read “Part I – Item 1. — Business —Bankruptcy and Plan of Reorganization” of this Form 10-K.

Recent Events Affecting Comparability of Periods

Acquisition of certain CHS retail stores

On January 9, 2018, we entered into the CHS Acquisition Agreement , to acquire twenty one (21) owned retail gasoline, convenience store facilities and twelve (12) leased retail gasoline, convenience store facilities, all at various locations in Washington and Idaho for a purchase price of approximately $70 million plus the agreed value of inventory at closing. The closing of the CHS Acquisition is subject to certain customary closing conditions and is expected to close in the first quarter of 2018. Please read Note 21—Subsequent Events to our consolidated financial statements under Item 8 of this Form 10-K for more information.

7.75% Senior Secured Notes Due 2025

On December 21, 2017 , Par Petroleum, LLC and Par Petroleum Finance Corp. , both our wholly-owned subsidiaries, completed the issuance and sale of $300 million in aggregate principal amount of 7.75% Senior Secured Notes due 2025 in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The net proceeds of $289.2 million (net of financing costs and original issue discount of approximately 1%) from the sale were used to repay our outstanding indebtness under the Hawaii Retail Credit Facilities , the Wyoming Refining Credit Facilities , the Par Wyoming Holdings Credit Agreement , and the J. Aron Forward Sale and for general corporate purposes. Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for more information.

ABL Credit Facility

On December 21, 2017 , in connection with the issuance of the 7.75% Senior Secured Notes , Par Petroleum, LLC , PHI, Mid Pac, HIE Retail, LLC, and WRC (collectively, the “ABL Borrowers”), entered into a Loan and Security Agreement dated as of December 21, 2017 (the “ ABL Credit Facility ”) with certain lenders and Bank of America, N.A., as administrative agent and collateral agent. The ABL Credit Facility provides for a revolving credit facility in the maximum principal amount at any time outstanding of $75 million , subject to a borrowing base, which provides for revolving loans and for the issuance of letters of credit (the " ABL Revolver "). The ABL Revolver was undrawn and had a borrowing base of approximately $48.7 million at December 31, 2017. Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Amended and Restated J. Aron Supply and Offtake Agreements

On December 21, 2017, in connection with the issuance of the 7.75% Senior Secured Notes , Par Hawaii Refining, LLC entered into an Amended and Restated Supply and Offtake Agreement with J. Aron (as amended and restated, the “Supply and Offtake Agreements”) pertaining to crude oil supply and offtake arrangements for our Hawaii refinery. In connection with the entry into such amendment and restatement, certain collateral (including the mortgage liens on the real property and improvements comprising the Hawaii refinery and on all equipment used to operate the Hawaii refinery, the equity interests in PHR held by Par Petroleum, LLC, and certain other items of personal property) was released, and Par Petroleum, LLC issued an unsecured guaranty in favor of J. Aron pursuant to which Par Petroleum, LLC guarantees the payment and performance of certain liabilities of PHR under the Supply and Offtake Agreements. Additionally, during 2017, we amended the Supply and Offtake Agreements so that J. Aron may enter into agreements with third parties whereby J. Aron will remit payments to these third parties for refinery procurement contracts for which we will become immediately obligated to reimburse J. Aron. Please read Note 10—Inventory Financing Agreements to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Other Factors Affecting Comparability of Periods

We completed the WRC Acquisition on July 14, 2016 , for cash consideration of $209.4 million , including a deposit of $5.0 million paid in June 2016 and assumed debt consisting of term loans of $58.0 million and revolving loans of $10.1 million . The results of operations of WRC are included in our segments effective July 14, 2016. Please read Note 4—Acquisitions to our consolidated financial statements under Item 8 of this Form 10-K for more information.

On April 1, 2015 , we completed the acquisition of Mid Pac for cash consideration of $74.4 million . In connection with the acquisition, Mid Pac's pre-existing debt was fully repaid on the closing date for $45.3 million . The results of operations of Mid Pac are included in our segments effective April 1, 2015. Please read Note 4—Acquisitions to our consolidated financial statements under Item 8 of this Form 10-K for more information.

We have recast the segment information for the years ended December 31, 2016 and 2015 to reflect the elimination of the Texadian segment as a reportable segment beginning in the first quarter of 2017. As of December 31, 2017, Texadian ceased its business operations other than the disposal of certain assets and liquidation of inventory.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Net Income (Loss). During 2017 , our financial performance was primarily driven by improved crack spreads, which is reflected in a change in our net income (loss) from a net loss of $45.8 million for the year ended December 31, 2016 to net income of $72.6 million for the year ended December 31, 2017 . Other factors impacting our results period over period include the full-year contribution provided by Wyoming Refining, which was acquired on July 14, 2016, and an improvement in our Equity earnings (losses) from Laramie Energy, LLC , partially offset by a loss on termination of financing agreements and the change in value of the contingent consideration obligation during 2016.

Adjusted EBITDA and Adjusted Net Income (Loss). For the year ended December 31, 2017 , Adjusted EBITDA was $140.8 million compared to $33.5 million for the year ended December 31, 2016 . The change was primarily related to improved crack spreads and the full-year contribution provided by Wyoming Refining, which was acquired on July 14, 2016.

For the year ended December 31, 2017 , Adjusted Net Income (Loss) was income of approximately $82.8 million compared to a loss of $49.7 million for the year ended December 31, 2016 . The change was primarily related to improved crack spreads, the full-year contribution provided by Wyoming Refining, and an improvement in our Equity earnings (losses) for Laramie Energy, LLC, partially offset by an increase in Interest expense and financing costs, net .

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Net Loss. During 2016, our financial performance was impacted by the turnaround at our Hawaii refinery and poor global crack spreads, which is reflected in an increase in our net loss from $39.9 million for the year ended December 31, 2015 to $45.8 million for the year ended December 31, 2016. Other factors impacting our results period over period include the termination of certain financing agreements in 2015, the change in value of our contingent consideration obligation, decreases in impairment expense and in our equity losses from Laramie Energy, an increase in interest expense, and the releases of valuation allowances as further discussed below.

Adjusted EBITDA and Adjusted Net Income (Loss). For the year ended December 31, 2016, Adjusted EBITDA was $33.5 million compared to $111.0 million for the year ended December 31, 2015. The change was primarily related to higher production and maintenance costs associated with the turnaround at our Hawaii refinery and lower crack spreads, partially offset by improved crude oil differentials, the contribution provided by Wyoming Refining, which was acquired on July 14, 2016, and the full-year contribution provided by Mid Pac, which was acquired on April 1, 2015.

For the year ended December 31, 2016, Adjusted Net Income (Loss) was a loss of $49.7 million compared to income of $15.0 million for the year ended December 31, 2015. The change was primarily related to higher production and maintenance costs associated with the turnaround at our Hawaii refinery, lower crack spreads, and higher interest expense and depreciation, depletion, and amortization (“DD&A”), partially offset by improved crude oil differentials, a decrease in our equity losses from Laramie Energy, the contribution provided by Wyoming Refining, which was acquired on July 14, 2016, and the full-year contribution provided by Mid Pac, which was acquired on April 1, 2015.

The following table summarizes our consolidated results of operations for the years ended December 31, 2017 , 2016 , and 2015 . The following should be read in conjunction with our consolidated financial statements under Item 8 of this Annual Report on Form 10-K.

	Year Ended December 31,		
	2017	2016	2015
Revenues	$ 2,443,066	$ 1,865,045	$ 2,066,337
Cost of revenues (excluding depreciation)	2,054,627	1,636,339	1,787,368
Operating expense (excluding depreciation)	202,019	166,216	141,621
Depreciation, depletion, and amortization	45,989	31,617	19,918
Impairment expense	—	—	9,639
General and administrative expense (excluding depreciation)	46,078	42,073	44,271
Acquisition and integration expense	395	5,294	2,006
Total operating expenses	2,349,108	1,881,539	2,004,823
Operating income (loss)	93,958	(16,494)	61,514
Other income (expense)			
Interest expense and financing costs, net	(31,632)	(28,506)	(20,156)
Loss on termination of financing agreements	(8,633)	—	(19,669)
Other income (expense), net	914	(98)	(291)
Change in value of common stock warrants	(1,674)	2,962	(3,664)
Change in value of contingent consideration	—	10,770	(18,450)
Equity earnings (losses) from Laramie Energy, LLC	18,369	(22,381)	(55,983)
Total other expense, net	(22,656)	(37,253)	(118,213)
Income (loss) before income taxes	71,302	(53,747)	(56,699)
Income tax benefit (expense)	1,319	7,912	16,788
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)

The following tables summarize our operating income (loss) by segment for the years ended December 31, 2017 , 2016 , and 2015 . The following should be read in conjunction with our consolidated financial statements under Item 8 of this Annual Report on Form 10-K.

Year ended December 31, 2017	Refining	Logistics (1)	Retail	Corporate, Eliminations and Other (2)	Total
Revenues	$ 2,319,638	$ 121,470	$ 326,076	$ (324,118)	$ 2,443,066
Cost of revenues (excluding depreciation)	2,062,804	66,301	249,097	(323,575)	2,054,627
Operating expense (excluding depreciation)	141,068	15,010	45,941	—	202,019
Depreciation, depletion, and amortization	29,753	6,166	6,338	3,732	45,989
General and administrative expense (excluding depreciation)	—	—	—	46,078	46,078
Acquisition and integration expense	—	—	—	395	395
Operating income (loss)	$ 86,013	$ 33,993	$ 24,700	$ (50,748)	$ 93,958

Year ended December 31, 2016	Refining	Logistics (1)	Retail	Corporate, Eliminations and Other (2)	Total
Revenues	$ 1,702,463	$ 102,779	$ 290,402	$ (230,599)	$ 1,865,045
Cost of revenues (excluding depreciation)	1,580,014	65,439	220,545	(229,659)	1,636,339
Operating expense (excluding depreciation)	112,724	11,239	41,291	962	166,216
Depreciation, depletion, and amortization	17,565	4,679	6,372	3,001	31,617
General and administrative expense (excluding depreciation)	—	—	—	42,073	42,073
Acquisition and integration expense	—	—	—	5,294	5,294
Operating income (loss)	$ (7,840)	$ 21,422	$ 22,194	$ (52,270)	$ (16,494)

Year ended December 31, 2015	Refining	Logistics (1)	Retail	Corporate, Eliminations and Other (2)	Total
Revenues	$ 1,895,662	$ 82,671	$ 283,507	$ (195,503)	$ 2,066,337
Cost of revenues (excluding depreciation)	1,718,729	48,660	215,194	(195,215)	1,787,368
Operating expense (excluding depreciation)	95,588	5,433	35,317	5,283	141,621
Depreciation, depletion, and amortization	9,522	3,117	5,421	1,858	19,918
Impairment expense	—	—	—	9,639	9,639
General and administrative expense (excluding depreciation)	—	—	—	44,271	44,271
Acquisition and integration expense	—	—	—	2,006	2,006
Operating income (loss)	$ 71,823	$ 25,461	$ 27,575	$ (63,345)	$ 61,514

(1) Our logistics operations consist primarily of intercompany transactions which eliminate on a consolidated basis.

(2) Includes eliminations of intersegment Revenues and Cost of revenues (excluding depreciation) of $325.2 million , $271.9 million , and $330.0 million for the year s ended December 31, 2017 , 2016 , and 2015 , respectively.

Below is a summary of key operating statistics for the refining segment for the year s ended December 31, 2017 , 2016 , and 2015 :

	Year Ended December 31,		
	2017	2016	2015
Total Refining Segment			
Feedstocks Throughput (Mbpd) (1)	89.2	86.0	77.3
Refined product sales volume (Mbpd) (1)	90.7	90.6	76.8
Hawaii Refinery			
Feedstocks Throughput (Mbpd)	73.7	70.2	77.3
Source of Crude Oil:			
North America	23.8%	41.7%	47.7%
Latin America	0.1%	3.9%	8.0%
Africa	24.9%	13.7%	8.3%
Asia	23.1%	30.0%	33.0%
Middle East	28.1%	10.7%	2.1%
Europe	—%	—%	0.9%
Total	100.0%	100.0%	100.0%
Yield (% of total throughput)			
Gasoline and gasoline blendstocks	27.8%	26.8%	26.2%
Distillate	48.2%	44.7%	44.1%
Fuel oils	15.7%	20.1%	22.0%
Other products	5.0%	4.8%	4.7%
Total yield	96.7%	96.4%	97.0%
Refined product sales volume (Mbpd)			
On-island sales volume	63.3	61.7	62.4
Exports sale volume	11.4	12.5	14.4
Total refined product sales volume	74.7	74.2	76.8
4-1-2-1 Singapore Crack Spread (2) ($ per barrel)	$ 7.18	$ 3.74	$ 6.88
4-1-2-1 Mid Pacific Crack Spread (2) ($ per barrel)	8.45	4.96	8.31
Mid Pacific Crude Oil Differential (3) ($ per barrel)	(0.54)	(2.01)	(1.50)
Operating income (loss) per bbl ($/throughput bbl)	2.13	(0.43)	2.55
Adjusted Gross Margin per bbl ($/throughput bbl) (4)	6.43	4.49	6.82
Production costs per bbl ($/throughput bbl) (5)	3.60	3.72	3.54
DD&A per bbl ($/throughput bbl)	0.64	0.45	0.34

	Year Ended December 31,	July 14, 2016 to December 31,
	2017	2016
Wyoming Refinery		
Feedstocks Throughput (Mbpd) (1)	15.5	15.8
Yield (% of total throughput)		
Gasoline and gasoline blendstocks	51.9%	56.0%
Distillate	42.8%	39.3%
Fuel oil	2.2%	1.9%
Other products	0.8%	1.0%
Total yield	97.7%	98.2%
Refined product sales volume (Mbpd) (1)	16.0	16.4
Wyoming 3-2-1 Index (6) ($ per barrel)	$ 21.80	$ 16.27
Operating income (loss) per bbl ($/throughput bbl)	5.09	1.20
Adjusted Gross Margin per bbl ($/throughput bbl) (4)	14.46	8.78
Production costs per bbl ($/throughput bbl) (5)	7.18	4.93
DD&A per bbl ($/throughput bbl)	2.19	2.25

(1) Feedstocks throughput and sales volumes per day for the Wyoming refinery are calculated based on the 171 day period for which we owned Wyoming Refining in 2016. As such, the amounts for the total refining segment represent the sum of the Hawaii refinery's throughput or sales volumes averaged over the year plus the Wyoming refinery's throughput or sales volumes averaged over the period from July 14, 2016 to December 31, 2016. The 2017 amounts for the total refining segment represent the sum of the Hawaii and Wyoming refineries' throughput or sales volumes averaged over the year ended December 31, 2017 .

(2) The profitability of our Hawaii business is heavily influenced by crack spreads in both the Singapore and U.S. West Coast markets. These markets reflect the closest liquid market alternatives to source refined products for Hawaii. We believe the Singapore and Mid Pacific crack spreads (or four barrels of Brent crude converted into one barrel of gasoline, two barrels of distillate (diesel and jet fuel), and one barrel of fuel oil) best reflect a market indicator for our Hawaii refinery operations. The Mid Pacific crack spread is calculated using a ratio of 80% Singapore and 20% San Francisco indices.

(3) Weighted-average differentials, excluding shipping costs, of a blend of crudes with an API of 31.98 and sulfur weight percentage of 0.65% that is indicative of our typical crude oil mix quality compared to Brent crude.

(4) Please see discussion of Adjusted Gross Margin below. We calculate Adjusted Gross Margin per barrel by dividing Adjusted Gross Margin by total refining throughput.

(5) Management uses production costs per barrel to evaluate performance and compare efficiency to other companies in the industry. There are a variety of ways to calculate production costs per barrel; different companies within the industry calculate it in different ways. We calculate production costs per barrel by dividing all direct production costs, which include the costs to run the refineries including personnel costs, repair and maintenance costs, insurance, utilities, and other miscellaneous costs, by total refining throughput. Our production costs are included in Operating expense (excluding depreciation) on our consolidated statement of operations, which also includes costs related to our bulk marketing operations.

(6) The profitability of our Wyoming refinery is heavily influenced by crack spreads in nearby markets. We believe the Wyoming 3-2-1 Index is the best market indicator for our operations in Wyoming. The Wyoming 3-2-1 Index is computed by taking two parts gasoline and one part distillate (ULSD) as created from three barrels of WTI. Pricing is based 50% on applicable product pricing in Rapid City, South Dakota, and 50% on applicable product pricing in Denver, Colorado.

Below is a summary of key operating statistics for the retail and logistics segments for the year s ended December 31, 2017 , 2016 , and 2015 :

	Year Ended December 31,		
	2017	2016	2015
Retail Segment			
Retail sales volumes (thousands of gallons)	92,739	90,941	80,649
Logistics Segment			
Pipeline throughput (Mbpd) (1)			
Crude oil pipelines	85.0	87.3	77.7
Refined product pipelines	87.4	85.8	68.9
Total pipeline throughput	172.4	173.1	146.6

(1) The 2016 amounts for the total logistics segment represent the sum of the pipeline throughput in Hawaii averaged over the year plus the pipeline throughput in Wyoming averaged over the period from July 14, 2016 to December 31, 2016. The 2017 amounts for the total logistics segment represent the sum of the Hawaii and Wyoming pipelines' throughput averaged over the year ended December 31, 2017 .

Non-GAAP Performance Measures

Management uses certain financial measures to evaluate our operating performance that are considered non-GAAP financial measures. These measures should not be considered a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP and our calculations thereof may not be comparable to similarly titled measures reported by other companies.

Adjusted Gross Margin. Adjusted Gross Margin is defined as (i) operating income (loss) plus operating expense (excluding depreciation), DD&A, impairment expense, inventory valuation adjustments (which adjusts for timing differences to reflect the economics of our inventory financing agreements, including lower of cost or net realizable value adjustments, the impact of the embedded derivative repurchase obligation, and purchase price allocation adjustments), and unrealized gains (losses) on derivatives or (ii) revenues less cost of revenues (excluding depreciation) less inventory valuation adjustments and unrealized gains (losses) on derivatives. We define cost of revenues (excluding depreciation) as the hydrocarbon-related costs of inventory sold, transportation costs of delivering product to customers, crude oil consumed in the refining process, costs to satisfy our RINS obligations and certain hydrocarbon fees, and taxes. Cost of revenues (excluding depreciation) also includes the unrealized gains (losses) on derivatives and inventory valuation adjustments that we exclude from Adjusted Gross Margin.

Management believes Adjusted Gross Margin is an important measure of operating performance and uses Adjusted Gross Margin per barrel to evaluate operating performance and compare profitability to other companies in the industry and to industry benchmarks. Management believes Adjusted Gross Margin provides useful information to investors because it eliminates the gross impact of volatile commodity prices and adjusts for certain non-cash items and timing differences created by our inventory financing agreement and lower of cost or net realizable value adjustments to demonstrate the earnings potential of the business before other fixed and variable costs, which are reported separately in Operating expense (excluding depreciation) and Depreciation, depletion, and amortization .

Adjusted Gross Margin should not be considered an alternative to operating income (loss), net cash flows from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP. Adjusted Gross Margin presented by other companies may not be comparable to our presentation since each company may define this term differently as they may include other manufacturing costs and depreciation expense in cost of revenues.

The following tables present a reconciliation of Adjusted Gross Margin to the most directly comparable GAAP financial measure, operating income (loss), on a historical basis, for selected segments, for the periods indicated (in thousands):

Year ended December 31, 2017	Refining	Logistics	Retail
Operating income (loss)	$ 86,013	$ 33,993	$ 24,700
Operating expense (excluding depreciation)	141,068	15,010	45,941
Depreciation, depletion, and amortization	29,753	6,166	6,338
Inventory valuation adjustment	(1,461)	—	—
Unrealized gain on derivatives	(623)	—	—
Adjusted Gross Margin	$ 254,750	$ 55,169	$ 76,979

Year ended December 31, 2016	Refining	Logistics	Retail
Operating income (loss)	$ (7,840)	$ 21,422	$ 22,194
Operating expense (excluding depreciation)	112,724	11,239	41,291
Depreciation, depletion, and amortization	17,565	4,679	6,372
Inventory valuation adjustment	29,056	—	—
Unrealized gain on derivatives	(12,438)	—	—
Adjusted Gross Margin	$ 139,067	$ 37,340	$ 69,857

Year ended December 31, 2015	Refining	Logistics	Retail
Operating income (loss)	$ 71,823	$ 25,461	$ 27,575
Operating expense (excluding depreciation)	95,588	5,433	35,317
Depreciation, depletion, and amortization	9,522	3,117	5,421
Inventory valuation adjustment	5,178	—	—
Unrealized loss on derivatives	10,284	—	—
Adjusted Gross Margin	$ 192,395	$ 34,011	$ 68,313

Adjusted Net Income (Loss) and Adjusted EBITDA. Adjusted Net Income (Loss) is defined as net income (loss) excluding changes in the value of contingent consideration and common stock warrants, acquisition and integration expense, unrealized (gains) losses on derivatives, loss on termination of financing agreements, impairment expense, release of tax valuation allowance, and inventory valuation adjustment. Beginning in 2017, Adjusted Net Income (Loss) also excludes severance costs. We have recast the non-GAAP information for the years ended December 31, 2016 and 2015 to conform with the current period presentation.

Adjusted EBITDA is Adjusted Net Income (Loss) excluding interest, taxes, DD&A, and our equity losses (earnings) from Laramie Energy. We believe Adjusted Net Income (Loss) and Adjusted EBITDA are useful supplemental financial measures that allow investors to assess:

- The financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- The ability of our assets to generate cash to pay interest on our indebtedness; and
- Our operating performance and return on invested capital as compared to other companies without regard to financing methods and capital structure.

Adjusted Net Income (Loss) and Adjusted EBITDA should not be considered in isolation or as a substitute for operating income (loss), net income (loss), cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted Net Income (Loss) and Adjusted EBITDA presented by other companies may not be comparable to our presentation as other companies may define these terms differently.

The following table presents a reconciliation of Adjusted Net Income (Loss) and Adjusted EBITDA to the most directly comparable GAAP financial measure, net income (loss), on a historical basis for the periods indicated (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Inventory valuation adjustment	(1,461)	25,101	6,689
Unrealized loss (gain) on derivatives	(623)	(12,034)	10,896
Acquisition and integration expense	395	5,294	2,006
Loss on termination of financing agreements	8,633	—	19,669
Increase in (release of) tax valuation allowance (1)	—	(8,573)	(16,759)
Change in value of common stock warrants	1,674	(2,962)	3,664
Change in value of contingent consideration	—	(10,770)	18,450
Severance costs	1,595	105	637
Impairment expense	—	—	9,639
Adjusted Net Income (Loss)	82,834	(49,674)	14,980
Depreciation, depletion, and amortization	45,989	31,617	19,918
Interest expense and financing costs, net	31,632	28,506	20,156
Equity losses (earnings) from Laramie Energy, LLC	(18,369)	22,381	55,983
Income tax expense (benefit)	(1,319)	661	(29)
Adjusted EBITDA	$ 140,767	$ 33,491	$ 111,008

(1) Included in Income tax benefit on our consolidated statements of operations.

Discussion of Operating Income by Segment

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Refining. Operating income for our refining segment was $86.0 million for the year ended December 31, 2017 , an increase of $93.8 million compared to an operating loss of $7.8 million for the year ended December 31, 2016 . The increase in profitability was primarily driven by higher crack spreads and the full year contribution of Wyoming Refining. The Mid Pacific crack spread increased 70% from $4.96 per barrel for the year ended December 31, 2016 to $8.45 per barrel for the year ended December 31, 2017 . The increase in crack spreads was partially offset by decreased crude oil differentials. The Mid Pacific crude oil differential decreased 73% from $2.01 per barrel for the year ended December 31, 2016 to $0.54 per barrel for the year ended December 31, 2017 .Wyoming Refining contributed operating income of approximately $28.8 million to the refining segment for the year ended December 31, 2017 as compared to approximately $3.2 million for the year ended December 31, 2016 .

Logistics. Operating income for our logistics segment was $34.0 million for the year ended December 31, 2017 , an increase of $12.6 million compared to operating income of $21.4 million for the year ended December 31, 2016 . The increase in profitability was primarily due to the full year contribution of Wyoming Refining and higher transportation and logistics services revenue. Wyoming Refining contributed operating income of approximately $6.0 million to the logistics segment for the year ended December 31, 2017 as compared to approximately $0.8 million for the year ended December 31, 2016 .

Retail. Operating income for our retail segment was $24.7 million for the year ended December 31, 2017 , an increase of $2.5 million compared to operating income of $22.2 million for the year ended December 31, 2016 . The increase in profitability was primarily due to an increase in sales prices of 12% and an increase in sales volumes of 2% , partially offset by a 11% increase in fuel costs and higher operating expenses.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Refining. The operating loss for our refining segment was $7.8 million for the year ended December 31, 2016, a decrease of $79.6 million compared to operating income of $71.8 million for the year ended December 31, 2015. The decrease in profitability was primarily driven by lower crack spreads and the turnaround at our Hawaii refinery in 2016. The Mid Pacific crack spread decreased 40% from $8.31 per barrel for the year ended December 31, 2015 to $4.96 per barrel for the year ended December 31, 2016. The decrease in crack spreads was partially offset by improved crude oil differentials. The Mid Pacific crude oil differential increased 34% from $1.50 per barrel for the year ended December 31, 2015 to $2.01 per barrel for the year ended December 31, 2016. The downtime associated with the turnaround resulted in higher production costs per throughput barrel of $3.72 for the year ended December 31, 2016 compared to $3.54 for the year ended December 31, 2015. We imported an additional 8 thousand barrels per day of refined products to meet customer demand during the turnaround, which significantly contributed to our low margin realization during the third quarter of 2016. We also incurred approximately $1.0 million of repair and maintenance expenses associated with the turnaround. Wyoming Refining contributed approximately $3.2 million of operating income to the refining segment for the year ended December 31, 2016.

Logistics. Operating income for our logistics segment was $21.4 million for the year ended December 31, 2016, a decrease of $4.1 million compared to operating income of $25.5 million for the year ended December 31, 2015. The decrease in profitability is primarily due to repair and maintenance expenses of $3.6 million related to the Hawaii subsea pipeline and a decrease in pipeline throughput in Hawaii from 146.6 Mbpd for the year ended December 31, 2015 to 141.5 Mbpd for the year ended December 31, 2016 driven by the Hawaii refinery turnaround. Wyoming Refining contributed approximately $0.8 million of operating income to the logistics segment for the year ended December 31, 2016.

Retail. Operating income for our retail segment was $22.2 million for the year ended December 31, 2016, a decrease of $5.4 million compared to operating income of $27.6 million for the year ended December 31, 2015. The decrease in profitability was primarily due to a decrease in sales prices of 9%. The decrease in sales prices was partially offset by the acquisition of Mid Pac on April 1, 2015 which contributed $12.1 million of operating income for the year ended December 31, 2016 to our retail segment as compared to $10.2 million for the year ended December 31, 2015.

Discussion of Adjusted Gross Margin by Segment

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Refining . For the year ended December 31, 2017 , our refining Adjusted Gross Margin was approximately $254.8 million , an increase of $115.7 million compared to $139.1 million for the year ended December 31, 2016 . The increase was primarily due to higher crack spreads and the full year contribution of Wyoming Refining. The Mid Pacific crack spread increased 70% from $4.96 per barrel for the year ended December 31, 2016 to $8.45 per barrel for the year ended December 31, 2017 . The increase in crack spreads was partially offset by decreased crude oil differentials. The Mid Pacific crude oil differential decreased 73% from $2.01 per barrel for the year ended December 31, 2016 to $0.54 per barrel for the year ended December 31, 2017 . Wyoming Refining contributed approximately $81.8 million and $23.7 million of Adjusted Gross Margin to the refining segment for the year s ended December 31, 2017 and 2016 , respectively.

Logistics . For the year ended December 31, 2017 , our logistics Adjusted Gross Margin was approximately $55.2 million , an increase of $17.9 million compared to $37.3 million for the year ended December 31, 2016 . The increase was primarily driven by the full year contribution of Wyoming Refining and lower maintenance project costs at our Hawaii refinery. Wyoming Refining contributed approximately $17.3 million and $5.1 million of Adjusted Gross Margin to the logistics segment for the year s ended December 31, 2017 and 2016 , respectively.

Retail . For the year ended December 31, 2017 , our retail Adjusted Gross Margin was approximately $77.0 million , an increase of $7.1 million compared to $69.9 million for the year ended December 31, 2016 . The increase was primarily due to an increase of 12% in sales prices and an increase in sales volumes of 2% , partially offset by a 11% increase in fuel costs.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Refining . For the year ended December 31, 2016, our refining Adjusted Gross Margin was approximately $139.1 million, a decrease of $53.3 million compared to $192.4 million for the year ended December 31, 2015. The decrease was primarily due to lower crack spreads and the turnaround at our Hawaii refinery in 2016. The Mid Pacific crack spread decreased 40% from $8.31 per barrel for the year ended December 31, 2015 to $4.96 per barrel for the year ended December 31, 2016. The decrease in crack spreads was partially offset by improved crude oil differentials. The Mid Pacific crude oil differential increased 34% from $1.50 per barrel for the year ended December 31, 2015 to $2.01 per barrel for the year ended December 31, 2016. The decrease was also due to high feedstock costs driven by the purchase of higher-cost crude oil and the additional import of 8 thousand barrels per day of refined products to meet customer demand during the turnaround. Wyoming Refining contributed approximately $23.7 million of Adjusted Gross Margin to the refining segment for the year ended December 31, 2016.

Logistics . For the year ended December 31, 2016, our logistics Adjusted Gross Margin was approximately $37.3 million, an increase of $3.3 million compared to $34.0 million for the year ended December 31, 2015. The increase was primarily driven by the acquisition of Wyoming Refining, which contributed approximately $5.1 million of Adjusted Gross Margin to the logistics segment for the year ended December 31, 2016.

Retail . For the year ended December 31, 2016, our retail Adjusted Gross Margin was approximately $69.9 million, an increase of $1.6 million compared to $68.3 million for the year ended December 31, 2015. The increase was driven by a 13% increase in sales volumes, which is primarily attributed to a full year of contribution by Mid Pac, which was acquired on April 1, 2015. This increase in volumes was offset by a decrease of 9% in sales prices that caused a compression in retail fuel margins (sales price of fuel charged to retail customers “at the pump” minus cost of fuel paid to our suppliers) as costs did not decrease at the same rate as prices.

Discussion of Consolidated Results

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Revenues. For the year ended December 31, 2017 , revenues were $2.4 billion , a $0.5 billion increase compared to $1.9 billion for the year ended December 31, 2016 . The increase was primarily due to an increase of $0.6 billion in third-party revenues at our refining segment, which was primarily the result of higher crude oil prices and the full year contribution of Wyoming Refining. Brent crude oil prices averaged $54.82 per barrel in the year ended December 31, 2017 compared to $45.14 per barrel in the year ended December 31, 2016 , with similar increases experienced for WTI crude oil prices. Wyoming Refining contributed revenues of $408.4 million and $168.6 million to the refining segment for the year s ended December 31, 2017 and 2016 , respectively. Revenues in our retail segment increase d $35.7 million primarily driven by an increase of 12% in sales prices.

Cost of Revenues (Excluding Depreciation). For the year ended December 31, 2017 , cost of revenues (excluding depreciation) , was $2.1 billion , a $0.5 billion increase compared to $1.6 billion for the year ended December 31, 2016 . The increase was primarily due to an increase of $0.5 billion in third-party cost of revenues (excluding depreciation) at our refining segment which was primarily the result of the full year contribution of Wyoming Refining and higher crude oil prices as discussed above. Wyoming Refining contributed cost of revenues (excluding depreciation) of $326.6 million and $145.9 million to the refining segment for the year s ended December 31, 2017 and 2016 , respectively. Cost of revenues (excluding depreciation) in our retail segment increase d $28.6 million primarily driven by 11% increase in fuel costs.

Operating Expense (Excluding Depreciation). For the year ended December 31, 2017 , operating expense (excluding depreciation) was approximately $202.0 million , an increase of $35.8 million compared to $166.2 million for the year ended December 31, 2016 . The increase was primarily due to the full year contribution of Wyoming Refining, which contributed $48.9 million and $16.8 million for the year s ended December 31, 2017 and 2016 , respectively.

Depreciation, Depletion, and Amortization . For the year ended December 31, 2017 , DD&A expense was approximately $46.0 million , an increase of $14.4 million compared to $31.6 million for the year ended December 31, 2016 . The increase was primarily due to DD&A related to assets acquired as part of the Wyoming Refining acquisition on July 14, 2016. Wyoming Refining contributed $15.5 million and $6.8 million of DD&A expense for the year s ended December 31, 2017 and 2016 , respectively. Additionally, amortization of deferred turnaround expenditures increased $6.8 million during the year ended December 31, 2017 compared to the same period in 2016 .

General and Administrative Expense (Excluding Depreciation). For the year ended December 31, 2017 , general and administrative expense (excluding depreciation) was approximately $46.1 million , an increase of $4.0 million compared to $42.1 million for the year ended December 31, 2016 . The increase is primarily due to higher payroll and employee benefit costs driven by increased headcount and severance costs incurred during the first quarter of 2017.

Acquisition and Integration Expense. For the year ended December 31, 2017 , acquisition and integration expense was approximately $0.4 million , a decrease of $4.9 million compared to $5.3 million for the year ended December 31, 2016 . The decrease was primarily due to the completion of the WRC Acquisition in July 2016 compared to minor costs incurred in 2017 for the WRC integration and the pending CHS Acquisition .

Interest Expense and Financing Costs, Net . For the year ended December 31, 2017 , our interest expense and financing costs were approximately $31.6 million , an increase of $3.1 million compared to $28.5 million for the year ended December 31, 2016 . The increase was primarily due to higher interest expense and financing costs of $4.6 million related to the

Wyoming Refining Credit Facilities and Par Wyoming Holdings Credit Agreement entered into during the third quarter of 2016 in conjunction with the WRC Acquisition , higher interest expense of $5.0 million associated with our 5.00% Convertible Senior Notes issued during the second quarter of 2016, and a $2.0 million reduction in the gain on interest rate swaps for the year ended December 31, 2017 . These increases were partially offset by lower interest expense of $6.1 million due to the full repayment and termination of the Term Loan during the second quarter of 2017 and lower interest expense and financing costs of approximately $3.0 million due to the full repayment and termination of the Bridge Notes in the third quarter of 2016. Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for further discussion on our indebtedness.

Change in Value of Common Stock Warrants . For the year ended December 31, 2017 , the change in value of common stock warrants resulted in a loss of approximately $1.7 million , a change of $4.7 million compared to a gain of $3.0 million for the year ended December 31, 2016 . For the year ended December 31, 2017 , our stock price increased from $14.54 per share as of December 31, 2016 to $19.28 per share as of December 31, 2017 which resulted in an increase in the fair value of the common stock warrants. During the year ended December 31, 2016 , our stock price decreased from $23.54 per share on December 31, 2015 to $14.54 per share on December 31, 2016 , which resulted in a decrease in the value of the common stock warrants.

Change in Value of Contingent Consideration . For the year ended December 31, 2017 , there was no change in value of our contingent consideration liability. For the year ended December 31, 2016 , the change in the value of our contingent consideration liability resulted in a gain of $10.8 million due to a decrease in our expected cash flows related to PHR for 2016 as a result of lower crack spreads. As of December 31, 2016, the earn-out measurement period related to the contingent consideration for the acquisition of PHR was complete. Please read Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Loss on Termination of Financing Agreements. For the year ended December 31, 2017 , our loss on termination of financing agreements was approximately $8.6 million and represents early termination fees and the acceleration of deferred amortization costs in connection with the termination of the Term Loan during the second quarter of 2017 and the termination and repayment of our outstanding indebtedness under the Hawaii Retail Credit Facilities , the Wyoming Refining Credit Facilities , the Par Wyoming Holdings Credit Agreement , and the J. Aron Forward Sale in the fourth quarter of 2017. No such loss was incurred in 2016 .

Equity Losses From Laramie Energy . For the year ended December 31, 2017 , equity earnings from Laramie were approximately $18.4 million , a change of $40.8 million compared to equity losses of $22.4 million for the year ended December 31, 2016 . The change was primarily due to an increase in production volumes, natural gas prices, and an increase in our share of Laramie Energy's gain (loss) on derivative instruments of $26.8 million for the year ended December 31, 2017 compared to the same period in 2016 .

Income Taxes. For the year ended December 31, 2017 , we recorded an income tax benefit of $1.3 million primarily due to the release of $0.8 million of valuation allowance associated with the U.S. tax reform legislation that converted the Alternative Minimum Tax Credit Carryovers to refundable credits. For the year ended December 31, 2016 , we recorded an income tax benefit of $7.9 million primarily due to the release of $8.6 million of our valuation allowance as we expect to be able to utilize a portion of our net operating loss (“NOL”) carryforwards to offset future taxable income associated with the reversal of the deferred tax liability recognized upon issuance of our 5.00% Convertible Senior Notes .

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

Revenues. For the year ended December 31, 2016, revenues were $1.9 billion, a $0.2 billion decrease compared to $2.1 billion for the year ended December 31, 2015. The decrease was primarily due to reductions of $183.7 million and $91.4 million in third-party revenues at our refining segment and the Texadian operations within our corporate and other segment, respectively, as a result of global declines in crude oil prices. Brent crude oil prices averaged $45.14 per barrel in the year ended December 31, 2016 compared to $53.58 per barrel in the year ended December 31, 2015, with similar decreases experienced for WTI crude oil prices. The decrease in oil prices was partially offset by the acquisition of Wyoming Refining on July 14, 2016, which contributed revenues of $168.6 million to the refining segment for the year ended December 31, 2016. Revenues in our retail segment increased $6.9 million primarily driven by a full year of Mid Pac operations, which contributed revenues for the retail segment of $124.1 million and $93.3 million for the years ended December 31, 2016 and 2015, respectively. The increase in retail revenues related to Mid Pac was partially offset by a decrease of 9% in sales prices.

Cost of Revenues (Excluding Depreciation). For the year ended December 31, 2016, cost of revenues (excluding depreciation), was $1.6 billion, a $0.2 billion decrease compared to $1.8 billion for the year ended December 31, 2015. The decrease was primarily due to reductions of $138.7 million and $92.7 million at our refining segment and the Texadian operations within our corporate and other segment, respectively, as a result of global declines in crude oil prices as discussed above. The decrease in crude oil prices was offset by high feedstock costs driven by higher-cost crude oil and the additional import of 8 thousand barrels per day in refined products during the turnaround at our Hawaii refinery. Wyoming Refining contributed cost of revenues (excluding depreciation) of $145.9 million to the refining segment for the year ended December 31, 2016. Cost of revenues (excluding depreciation) in our retail segment increased $5.3 million primarily driven by a full year of Mid Pac operations, which contributed cost of revenues (excluding depreciation) for the retail segment of $92.5 million and $69.7 million for the years ended December 31, 2016 and 2015, respectively. The increase in cost of revenues (excluding depreciation) in our retail segment related to Mid Pac was partially offset by a decrease of 9% in the cost of refined product resulting from the global declines in crude oil prices as discussed above.

Operating Expense (Excluding Depreciation). For the year ended December 31, 2016, operating expense (excluding depreciation) was approximately $166.2 million, an increase of $24.6 million compared to $141.6 million for the year ended December 31, 2015. The increase was primarily due to the acquisition of Wyoming Refining and a full year of Mid Pac operations that contributed $16.8 million and $5.0 million to the increase in operating expense (excluding depreciation), respectively. Additionally, we chartered a new barge in 2016 that increased operating expense (excluding depreciation) by $2.0 million and repair and maintenance expense increased $4.6 million in connection with the Hawaii subsea pipeline and the turnaround of our Hawaii refinery. The increases were partially offset by a curtailment gain related to our Wyoming Refining pension plan of $3.1 million for the year ended December 31, 2016 and a decrease in lease operating expense due to shutting in operations at the Point Arguello Unit in offshore California during the third quarter of 2015.

Depreciation, Depletion, and Amortization . For the year ended December 31, 2016, DD&A expense was approximately $31.6 million, an increase of $11.7 million compared to $19.9 million for the year ended December 31, 2015. The increase was primarily due to DD&A of assets acquired as part of the Wyoming Refining acquisition on July 14, 2016 and a full year of Mid Pac operations. Wyoming Refining contributed $6.8 million of DD&A expense for the year ended December 31, 2016. Mid Pac contributed $6.0 million and $4.3 million of DD&A expense for the years ended December 31, 2016 and 2015, respectively. Additionally, we recognized amortization of deferred turnaround expenditures of $3.9 million for the year ended December 31, 2016.

Impairment Expense. For the year ended December 31, 2015, we recorded impairment charges of $9.6 million related to goodwill and intangible assets related to our Texadian operations. There was no impairment expense for the year ended December 31, 2016.

General and Administrative Expense (Excluding Depreciation). For the year ended December 31, 2016, general and administrative expense (excluding depreciation) was approximately $42.1 million, a decrease of $2.2 million compared to $44.3 million for the year ended December 31, 2015. The decrease is primarily due to lower compensation costs.

Acquisition and Integration Expense. For the year ended December 31, 2016, acquisition and integration expense was approximately $5.3 million, an increase of $3.3 million compared to $2.0 million for the year ended December 31, 2015. The increase was primarily due to the WRC Acquisition being completed in July 2016 and additional costs incurred in 2016 related to Mid Pac.

Interest Expense and Financing Costs, Net . For the year ended December 31, 2016, our interest expense and financing costs were approximately $28.5 million, an increase of $8.3 million compared to $20.2 million for the year ended December 31, 2015. The increase was primarily due to interest expense and financing costs of approximately $3.0 million related to the Bridge Notes, interest expense of $3.0 million associated with our 5.00% Convertible Senior Notes issued during the second quarter of 2016, interest expense of $3.9 million related to the Par Wyoming Holdings Credit Agreement, and interest expense of $1.3 million related to debt assumed in connection with the acquisition of Wyoming Refining. These increases were partially offset by a $2.7 million gain on interest rate swaps for the year ended December 31, 2016. We entered into interest rate swaps contracts in February 2016 to manage our interest rate risk.

Change in Value of Common Stock Warrants . For the year ended December 31, 2016, the change in value of common stock warrants resulted in a gain of approximately $3.0 million, a change of $6.7 million compared to a loss of $3.7 million for the year ended December 31, 2015. For the year ended December 31, 2016, our stock price decreased from $23.54 per share as of December 31, 2015 to $14.54 per share as of December 31, 2016 which resulted in a decrease in the fair value of the common stock warrants. During the year ended December 31, 2015, our stock price increased from $16.25 per share on December 31, 2014 to $23.54 per share on December 31, 2015, which resulted in an increase in the value of the common stock warrants.

Change in Value of Contingent Consideration . For the year ended December 31, 2016, the change in value of our contingent consideration liability resulted in a gain of approximately $10.8 million, a change of $29.3 million compared to a loss of $18.5 million for the year ended December 31, 2015. The contingent consideration relates to the acquisition of PHR which occurred on September 25, 2013 and the change in value was due to a decrease in cash flows related to PHR for 2016 as a result of lower crack spreads.

Loss on Termination of Financing Agreements. For the year ended December 31, 2015, our loss on the termination of financing agreements was approximately $19.7 million, which primarily consists of a loss of $17.4 million on the termination of the Barclays Supply and Exchange Agreements and a loss of $1.8 million on the termination of the asset-based senior secured revolving credit facility with PHR (the "HIE ABL Facility"). The loss of $17.4 million on the termination of the Supply and Exchange Agreements consists of a loss of $13.3 million for the cash settlement value of the liability and a loss of $5.6 million for the acceleration of deferred financing costs, partially offset by a $1.5 million exit fee received from Barclays. The loss on the termination of the HIE ABL Facility consisted of the accelerated amortization of deferred financing costs. No such loss was incurred in 2016.

Equity Losses From Laramie Energy . For the year ended December 31, 2016, equity losses from Laramie were approximately $22.4 million, a decrease in the loss of $33.6 million compared to equity losses of $56.0 million for the year ended December 31, 2015. The decrease in the loss was primarily due to an impairment of $41.1 million on our equity investment of Laramie Energy in 2015. No such impairment was incurred in 2016. This was offset by higher losses on Laramie Energy's commodity derivative instruments in the year ended December 31, 2016 compared to the same period in 2015.

Income Taxes. For the year ended December 31, 2016, we recorded an income tax benefit of $7.9 million primarily due to the release of $8.6 million of our valuation allowance as we expect to be able to utilize a portion of our net operating loss ("NOL") carryforwards to offset future taxable income associated with the reversal of the deferred tax liability recognized upon issuance of our 5.00% Convertible Senior Notes . For the year ended December 31, 2015, we recorded an income tax benefit of $16.8 million primarily due to the release of $16.8 million of our valuation allowance as we expect to be able to utilize a portion of our NOL carryforwards to offset future taxable income of Mid Pac.

Consolidating Condensed Financial Information

On December 21, 2017, Par Petroleum, LLC (the "Issuer"), issued its 7.75% Senior Secured Notes due 2025 in a private offering under Rule 144A and Regulation S of the Securities Act. The notes were co-issued by Par Petroleum Finance Corp., which has no independent assets or operations. The notes are guaranteed on a senior unsecured basis only as to payment of principal and interest by Par Pacific Holdings, Inc. (the "Parent") and are guaranteed on a senior secured basis by all of the subsidiaries of Par Petroleum, LLC (other than Par Petroleum Finance Corp.).

The following supplemental condensed consolidating financial information reflects (i) the Parent's separate accounts, (ii) Par Petroleum, LLC and its consolidated subsidiaries' accounts (which are all guarantors of the 7.75% Senior Secured Notes), (iii) the accounts of subsidiaries of the Parent that are not guarantors of the 7.75% Senior Secured Notes and consolidating adjustments and eliminations, and (iv) the Parent's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent's investment in its subsidiaries is accounted for under the equity method of accounting (dollar amounts in thousands).

	As of December 31, 2017			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
ASSETS				
Current assets				
Cash and cash equivalents	$ 65,615	$ 51,429	$ 1,289	$ 118,333
Restricted cash	744	—	—	744
Trade accounts receivable	—	120,032	1,799	121,831
Inventories	—	345,072	285	345,357
Prepaid and other current assets	11,768	7,115	(1,604)	17,279
Due from related parties	8,113	32,171	(40,284)	—
Total current assets	86,240	555,819	(38,515)	603,544
Property and equipment				
Property, plant, and equipment	15,773	513,307	158	529,238
Proved oil and gas properties, at cost, successful efforts method of accounting	—	—	400	400
Total property and equipment	15,773	513,307	558	529,638
Less accumulated depreciation and depletion	(6,226)	(73,029)	(367)	(79,622)
Property and equipment, net	9,547	440,278	191	450,016
Long-term assets				
Investment in Laramie Energy, LLC	—	—	127,192	127,192
Investment in subsidiaries	552,748	—	(552,748)	—
Intangible assets, net	—	26,604	—	26,604
Goodwill	—	104,589	2,598	107,187
Other long-term assets	1,976	30,888	—	32,864
Total assets	$ 650,511	$ 1,158,178	$ (461,282)	$ 1,347,407
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Obligations under inventory financing agreements	$ —	$ 363,756	$ —	$ 363,756
Accounts payable	4,510	46,273	1,760	52,543
Advances from customers	—	9,522	—	9,522
Accrued taxes	—	20,227	(2,540)	17,687
Other accrued liabilities	12,913	14,420	111	27,444
Due to related parties	82,524	—	(82,524)	—
Total current liabilities	99,947	454,198	(83,193)	470,952
Long-term liabilities				
Long-term debt, net of current maturities	95,486	289,326	—	384,812
Common stock warrants	6,808	—	—	6,808
Long-term capital lease obligations	551	669	—	1,220
Other liabilities	—	41,253	(5,357)	35,896
Total liabilities	202,792	785,446	(88,550)	899,688
Commitments and contingencies				
Stockholders' equity				
Preferred stock, $0.01 par value: 3,000,000 shares authorized, none issued	$ —	$ —	$ —	$ —
Common stock, $0.01 par value; 500,000,000 shares authorized and 45,776,087 shares issued	458	—	—	458
Additional paid-in capital	593,295	345,825	(345,825)	593,295
Accumulated earnings (deficit)	(148,178)	23,933	(23,933)	(148,178)
Accumulated other comprehensive income	2,144	2,974	(2,974)	2,144
Total stockholders' equity	447,719	372,732	(372,732)	447,719
Total liabilities and stockholders' equity	$ 650,511	$ 1,158,178	$ (461,282)	$ 1,347,407

	As of December 31, 2016			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
ASSETS				
Current assets				
Cash and cash equivalents	$ 10,361	$ 37,218	$ 193	$ 47,772
Restricted cash	746	—	500	1,246
Trade accounts receivable	—	99,869	2,515	102,384
Inventories	—	197,923	403	198,326
Prepaid and other current assets	9,200	44,180	—	53,380
Due from related parties	66,900	—	(66,900)	—
Total current assets	87,207	379,190	(63,289)	403,108
Property and equipment				
Property, plant, and equipment	10,259	489,450	158	499,867
Proved oil and gas properties, at cost, successful efforts method of accounting	—	—	1,122	1,122
Total property and equipment	10,259	489,450	1,280	500,989
Less accumulated depreciation and depletion	(3,485)	(45,255)	(987)	(49,727)
Property and equipment, net	6,774	444,195	293	451,262
Long-term assets				
Investment in Laramie Energy, LLC	—	—	108,823	108,823
Investment in subsidiaries	513,693	—	(513,693)	—
Intangible assets, net	—	29,262	650	29,912
Goodwill	—	103,134	2,598	105,732
Other long-term assets	1,976	44,404	216	46,596
Total assets	$ 609,650	$ 1,000,185	$ (464,402)	$ 1,145,433
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Current maturities of long-term debt	$ —	$ 20,286	$ —	$ 20,286
Obligations under inventory financing agreements	—	225,135	—	225,135
Accounts payable	4,529	58,739	1,922	65,190
Advances from customers	—	23,774	—	23,774
Accrued taxes	—	13,194	—	13,194
Other accrued liabilities	8,141	27,024	21	35,186
Due to related parties	73,529	8,525	(82,054)	—
Total current liabilities	86,199	376,677	(80,111)	382,765
Long-term liabilities				
Long-term debt, net of current maturities	148,456	201,654	—	350,110
Common stock warrants	5,134	—	—	5,134
Long-term capital lease obligations	952	828	—	1,780
Other liabilities	—	44,642	(7,907)	36,735
Total liabilities	240,741	623,801	(88,018)	776,524
Commitments and contingencies				
Stockholders' equity				
Preferred stock, $0.01 par value: 3,000,000 shares authorized, none issued	$ —	$ —	$ —	$ —
Common stock, $0.01 par value; 500,000,000 shares authorized and 45,533,913 shares issued	455	—	—	455
Additional paid-in capital	587,057	414,400	(414,400)	587,057
Accumulated deficit	(220,799)	(40,212)	40,212	(220,799)
Accumulated other comprehensive income	2,196	2,196	(2,196)	2,196
Total stockholders' equity	368,909	376,384	(376,384)	368,909
Total liabilities and stockholders' equity	$ 609,650	$ 1,000,185	$ (464,402)	$ 1,145,433

	Year Ended December 31, 2017			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
Revenues	$ —	$ 2,442,188	$ 878	$ 2,443,066
Operating expenses				
Cost of revenues (excluding depreciation)	—	2,053,757	870	2,054,627
Operating expense (excluding depreciation)	—	202,019	—	202,019
Depreciation, depletion, and amortization	2,871	42,368	750	45,989
General and administrative expense (excluding depreciation)	18,922	26,967	189	46,078
Acquisition and integration expense	192	—	203	395
Total operating expenses	21,985	2,325,111	2,012	2,349,108
Operating income (loss)	(21,985)	117,077	(1,134)	93,958
Other income (expense)				
Interest expense and financing costs, net	(13,709)	(17,923)	—	(31,632)
Interest income from subsidiaries	—	—	—	—
Loss on termination of financing agreements	(1,804)	(6,829)	—	(8,633)
Other income (expense), net	631	154	129	914
Change in value of common stock warrants	(1,674)	—	—	(1,674)
Equity earnings (losses) from subsidiaries	111,162	—	(111,162)	—
Equity earnings from Laramie Energy, LLC	—	—	18,369	18,369
Total other income (expense), net	94,606	(24,598)	(92,664)	(22,656)
Income (loss) before income taxes	72,621	92,479	(93,798)	71,302
Income tax benefit (expense)	—	(29,079)	30,398	1,319
Net income (loss)	$ 72,621	$ 63,400	$ (63,400)	$ 72,621
Adjusted EBITDA	$ (17,091)	$ 157,910	$ (52)	$ 140,767

	Year Ended December 31, 2016			
	Parent Guarantor	**Issuer**	**Non-Guarantor Subsidiaries and Eliminations**	**Par Pacific Holdings, Inc. and Subsidiaries**
Revenues	$ —	$ 1,823,527	$ 41,518	$ 1,865,045
Operating expenses				
Cost of revenues (excluding depreciation)	—	1,593,998	42,341	1,636,339
Operating expense (excluding depreciation)	—	166,318	(102)	166,216
Depreciation, depletion, and amortization	2,205	28,659	753	31,617
General and administrative expense (excluding depreciation)	15,618	22,458	3,997	42,073
Acquisition and integration expense	4,781	—	513	5,294
Total operating expenses	22,604	1,811,433	47,502	1,881,539
Operating income (loss)	(22,604)	12,094	(5,984)	(16,494)
Other income (expense)				
Interest expense and financing costs, net	(18,246)	(10,152)	(108)	(28,506)
Interest income from subsidiaries	583	—	(583)	—
Other income (expense), net	67	36	(201)	(98)
Change in value of common stock warrants	2,962	—	—	2,962
Change in value of contingent consideration	—	10,770	—	10,770
Equity losses from subsidiaries	(17,170)	—	17,170	—
Equity losses from Laramie Energy, LLC	—	—	(22,381)	(22,381)
Total other income (expense), net	(31,804)	654	(6,103)	(37,253)
Income (loss) before income taxes	(54,408)	12,748	(12,087)	(53,747)
Income tax benefit (expense)	8,573	(10,621)	9,960	7,912
Net income (loss)	$ (45,835)	$ 2,127	$ (2,127)	$ (45,835)
Adjusted EBITDA	$ (14,863)	$ 53,856	$ (5,502)	$ 33,491

	Year Ended December 31, 2015			
	Parent Guarantor	**Issuer**	**Non-Guarantor Subsidiaries and Eliminations**	**Par Pacific Holdings, Inc. and Subsidiaries**
Revenues	$ —	$ 1,993,004	$ 73,333	$ 2,066,337
Operating expenses				
Cost of revenues (excluding depreciation)	—	1,713,747	73,621	1,787,368
Operating expense (excluding depreciation)	—	135,947	5,674	141,621
Depreciation, depletion, and amortization	963	18,062	893	19,918
Impairment expense	—	—	9,639	9,639
General and administrative expense (excluding depreciation)	16,558	22,521	5,192	44,271
Acquisition and integration expense	1,776	—	230	2,006
Total operating expenses	19,297	1,890,277	95,249	2,004,823
Operating income (loss)	(19,297)	102,727	(21,916)	61,514
Other income (expense)				
Interest expense and financing costs, net	(13,028)	(5,931)	(1,197)	(20,156)
Interest income from subsidiaries	1,000	—	(1,000)	—
Loss on termination of financing agreements	—	(19,610)	(59)	(19,669)
Other income (expense), net	215	(453)	(53)	(291)
Change in value of common stock warrants	(3,664)	—	—	(3,664)
Change in value of contingent consideration	—	(18,450)	—	(18,450)
Equity losses from subsidiaries	(5,137)	—	5,137	—
Equity losses from Laramie Energy, LLC	—	—	(55,983)	(55,983)
Total other income (expense), net	(20,614)	(44,444)	(53,155)	(118,213)
Income (loss) before income taxes	(39,911)	58,283	(75,071)	(56,699)
Income tax benefit (expense)	—	(1,021)	17,809	16,788
Net income (loss)	$ (39,911)	$ 57,262	$ (57,262)	$ (39,911)
Adjusted EBITDA	$ (14,706)	$ 135,798	$ (10,084)	$ 111,008

Non-GAAP Financial Measures

Adjusted EBITDA for the supplemental consolidating condensed financial information, which is segregated at the "Parent Guarantor," "Issuer" and "Non-Guarantor Subsidiaries and Eliminations" levels, is calculated in the same manner as for the Par Pacific Holdings, Inc. Adjusted EBITDA calculations. See "Results of Operations — Non-GAAP Performance Measures — Adjusted Net Income (Loss) and Adjusted EBITDA" above.

The following tables present a reconciliation of Adjusted EBITDA to the most directly comparable GAAP financial measure, net income (loss), on a historical basis for the periods indicated (in thousands):

	Year Ended December 31, 2017			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
Net income (loss)	$ 72,621	$ 63,400	$ (63,400)	$ 72,621
Inventory valuation adjustment	—	(1,461)	—	(1,461)
Unrealized loss (gain) on derivatives	—	(623)	—	(623)
Acquisition and integration expense	192	—	203	395
Loss on termination of financing agreements	1,804	6,829	—	8,633
Change in value of common stock warrants	1,674	—	—	1,674
Severance costs	1,200	395	—	1,595
Depreciation, depletion, and amortization	2,871	42,368	750	45,989
Interest expense and financing costs, net	13,709	17,923	—	31,632
Equity losses (earnings) from Laramie Energy, LLC	—	—	(18,369)	(18,369)
Equity losses (income) from subsidiaries	(111,162)	—	111,162	—
Income tax expense (benefit)	—	29,079	(30,398)	(1,319)
Adjusted EBITDA	$ (17,091)	$ 157,910	$ (52)	$ 140,767

	Year Ended December 31, 2016			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
Net income (loss)	$ (45,835)	$ 2,127	$ (2,127)	$ (45,835)
Inventory valuation adjustment	—	25,101	—	25,101
Unrealized loss (gain) on derivatives	—	(12,034)	—	(12,034)
Acquisition and integration expense	4,781	—	513	5,294
Increase in (release of) tax valuation allowance (1)	(8,573)	—	—	(8,573)
Change in value of common stock warrants	(2,962)	—	—	(2,962)
Change in value of contingent consideration	—	(10,770)	—	(10,770)
Severance costs	105	—	—	105
Depreciation, depletion, and amortization	2,205	28,659	753	31,617
Interest expense and financing costs, net	18,246	10,152	108	28,506
Equity losses (earnings) from Laramie Energy, LLC	—	—	22,381	22,381
Equity losses from subsidiaries	17,170	—	(17,170)	—
Income tax expense (benefit)	—	10,621	(9,960)	661
Adjusted EBITDA	$ (14,863)	$ 53,856	$ (5,502)	$ 33,491

	Year Ended December 31, 2015			
	Parent Guarantor	Issuer	Non-Guarantor Subsidiaries and Eliminations	Par Pacific Holdings, Inc. and Subsidiaries
Net income (loss)	$ (39,911)	$ 57,262	$ (57,262)	$ (39,911)
Inventory valuation adjustment	—	5,178	1,511	6,689
Unrealized loss (gain) on derivatives	—	10,284	612	10,896
Acquisition and integration expense	1,776	—	230	2,006
Loss on termination of financing agreements	—	19,610	59	19,669
Increase in (release of) tax valuation allowance (1)	—	(21,710)	4,951	(16,759)
Change in value of common stock warrants	3,664	—	—	3,664
Change in value of contingent consideration	—	18,450	—	18,450
Severance costs	637	—	—	637
Impairment expense	—	—	9,639	9,639
Depreciation, depletion, and amortization	963	18,062	893	19,918
Interest expense and financing costs, net	13,028	5,931	1,197	20,156
Equity losses (earnings) from Laramie Energy, LLC	—	—	55,983	55,983
Equity losses from subsidiaries	5,137	—	(5,137)	—
Income tax expense (benefit)	—	22,731	(22,760)	(29)
Adjusted EBITDA	$ (14,706)	$ 135,798	$ (10,084)	$ 111,008

(1) Included in Income tax benefit on our consolidated statements of operations.

Liquidity and Capital Resources

Our liquidity and capital requirements are primarily a function of our debt maturities and debt service requirements, fixed capacity payments and contractual obligations, capital expenditures, and working capital needs. Examples of working capital needs include purchases and sales of commodities and associated margin and collateral requirements, facility maintenance costs, and other costs such as payroll. Our primary sources of liquidity are cash flows from operations, cash on hand, amounts available under our credit agreements, and access to capital markets.

Our liquidity position as of December 31, 2017 was $209.0 million and consisted of $142.4 million at Par Petroleum, LLC and subsidiaries, $65.6 million at Par Pacific Holdings, and $1 million at all our other subsidiaries. Our consolidated liquidity position as of March 7, 2018 was $227.6 million. The change in our liquidity position from December 31, 2017 to March 7, 2018 was primarily attributable to changes in working capital.

As of December 31, 2017 , we had access to a deferred payment arrangement with J. Aron, the ABL Credit Facility , and cash on hand of $118.3 million . In addition, we utilize the Supply and Offtake Agreements with J. Aron to finance the majority of the inventory at our Hawaii refinery. Generally, the primary uses of our capital resources have been in the operations of our refining and retail segments, payments related to acquisitions, to repay or refinance indebtedness, and cash capital contributions to Laramie Energy .

We believe our cash flows from operations and available capital resources will be sufficient to meet our current capital expenditures, working capital, and debt service requirements for the next 12 months. Additionally, we may seek to raise additional debt or equity capital to fund any other significant changes to our business or to refinance existing debt. We cannot offer any assurances that such capital will be available in sufficient amounts or at an acceptable cost.

Rights Offering

On September 22, 2016 , we issued approximately 4 million shares of our common stock to certain investors at a purchase price of $12.25 per share (the “Rights Offering”). The gross proceeds from the Rights Offering were approximately $49.9 million , before deducting expenses of approximately $0.9 million , for net proceeds of approximately

$49.0 million . The net proceeds from the Rights Offering were used to repay all accrued and unpaid interest and a portion of the outstanding principal amount on our Bridge Notes.

Debt Activity

We had the following significant debt issuances and amendments during the years ended December 31, 2017 , 2016 , and 2015 :

- On December 21, 2017 , Par Petroleum, LLC and Par Petroleum Finance Corp. , both our wholly-owned subsidiaries, completed the issuance and sale of $300 million in aggregate principal amount of 7.75% Senior Secured Notes due 2025 in a private placement under Rule 144A and Regulation S of the Securities Act. The net proceeds of $289.2 million (net of financing costs and original issue discount of 1%) from the sale were used to repay our outstanding indebtedness under the Hawaii Retail Credit Facilities , the Wyoming Refining Credit Facilities , the Par Wyoming Holdings Credit Agreement , and the J. Aron Forward Sale and for general corporate purposes.

- On December 21, 2017 , in connection with the issuance of the 7.75% Senior Secured Notes , the ABL Borrowers entered into the ABL Credit Facility dated as of December 21, 2017 , with certain lenders and Bank of America, N.A., as administrative agent and collateral agent. The ABL Credit Facility provides for a revolving credit facility in the maximum principal amount at any time outstanding of $75 million , subject to a borrowing base, which provides for revolving loans and for the issuance of letters of credit (the " ABL Revolver "). The ABL Revolver was undrawn and had a borrowing base of approximately $48.7 million at December 31, 2017 .

- On June 30, 2017, we fully repaid and terminated the Delayed Draw Term Loan and Bridge Loan Credit Agreement (the "Term Loan"). We recorded a loss on termination of approximately $1.8 million related to unamortized deferred financing costs associated with the Term Loan in the year ended December 31, 2017 .

- On July 14, 2016 , in connection with the WRC Acquisition , Par Wyoming Holdings, LLC, our indirect wholly owned subsidiary, entered into the Par Wyoming Holdings Credit Agreement with certain lenders and Chambers Energy Management, LP, as agent, which provided for a single advance secured term loan to our subsidiary in the amount of $65.0 million (the “ Par Wyoming Holdings Term Loan ”) at the closing of the WRC Acquisition . The proceeds of the Par Wyoming Holdings Term Loan were used to pay a portion of the consideration for the WRC Acquisition , to pay certain fees and closing costs, and for general corporate purposes. Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Par Wyoming Holdings Credit Agreement **.**

- On July 14, 2016 , in connection with the WRC Acquisition , we assumed debt consisting of term loans of $58.0 million and revolving loans of $10.1 million under a Third Amended and Restated Loan Agreement dated as of April 30, 2015 (as amended, the “ Wyoming Refining Credit Facilities ”), with Bank of America, N.A. The Wyoming Refining Credit Facilities also provided for a revolving credit facility in the maximum principal amount at any time outstanding of $30.0 million , subject to a borrowing base, which provides for revolving loans and for the issuance of letters of credit. Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Wyoming Refining Credit Facilities **.**

- On July 14, 2016 , we issued approximately $52.6 million in aggregate principal amount of the Bridge Notes in a private offering pursuant to the terms of a note purchase agreement (the “Note Purchase Agreement”) entered into among the purchasers of the Bridge Notes and us. The net proceeds from the sale of the Bridge Notes of $50.0 million were used to fund a portion of the consideration for the WRC Acquisition . On September 22, 2016 , we used the net proceeds from the Rights Offering to repay all accrued and unpaid interest and a portion of the outstanding principal amount on the Bridge Notes. The remaining $3.1 million aggregate principal amount and $0.3 million unpaid interest of the Bridge Notes was mandatorily converted into 272,733 shares of our common stock based on a conversion price of $12.25 per share.

- On June 21, 2016 and June 27, 2016, we completed the issuance and sale of $115.0 million in aggregate principal amount of the 5.00% Convertible Senior Notes in a private placement under Rule 144A (the “Convertible Notes Offering”). The Convertible Notes Offering included the exercise in full of an option to purchase an additional $15 million in aggregate principal amount of the 5.00% Convertible Senior Notes granted to the initial purchasers. The net proceeds of $111.6 million (net of original issue discount of 3%) from the sale of the 5.00% Convertible Senior Notes were used to finance a portion of the WRC Acquisition , to repay $5 million in principal amount of the Term Loan, and for general corporate purposes.

- On December 17, 2015 , HIE Retail, LLC ("HIE Retail") and Mid Pac entered into the Hawaii Retail Credit Facilities in the form of a revolving credit facility up to $5.0 million (“ Hawaii Retail Revolving Credit Facilities ”), which provided for revolving loans and for the issuance of letters of credit and term loans (“ Hawaii Retail Term Loans ”) in the aggregate principal amount of $110 million . The proceeds of the Hawaii Retail Term Loans were used to repay existing indebtedness under HIE Retail and Mid Pac's then existing credit agreements, to pay transaction fees and expenses, and to facilitate a cash distribution to us. Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Hawaii Retail Revolving Credit Facilities **.**

- As part of the May 8, 2017 amendment to the Supply and Offtake Agreements , we also entered into a $30 million forward sale of certain monthly volumes of jet fuel to be delivered to J. Aron over the remaining amended term (" J. Aron Forward Sale "). The proceeds from the J. Aron Forward Sale were used to pay a portion of the outstanding balance on the Term Loan. Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the J. Aron Forward Sale .

Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for further discussion on our debt agreements.

Cash Flows

The following table summarizes cash activities for the years ended December 31, 2017 , 2016 , and 2015 (in thousands):

	Years Ended December 31,		
	2017	**2016**	**2015**
Net cash provided by (used in) operating activities	$ 106,483	$ (23,891)	$ 132,358
Net cash used in investing activities	(31,171)	(286,243)	(114,205)
Net cash provided by (used in) financing activities	(4,751)	190,118	60,425

Net cash provided by operating activities was approximately $106.5 million for the year ended December 31, 2017 , which resulted from net income of approximately $72.6 million and non-cash charges to operations of approximately $50.1 million , offset by net cash used for changes in operating assets and liabilities of approximately $16.2 million . Net cash used in operating activities was approximately $23.9 million for the year ended December 31, 2016 , which resulted from a net loss of approximately $45.8 million and net cash used for changes in operating assets and liabilities of approximately $19.7 million , offset by non-cash charges to operations of approximately $41.6 million . Net cash provided by operating activities was approximately $132.4 million for the year ended December 31, 2015 , which resulted from a net loss of approximately $39.9 million , offset by non-cash charges to operations of approximately $133.8 million and net cash provided by changes in operating assets and liabilities of approximately $38.5 million .

For the year ended December 31, 2017 , net cash used in investing activities was approximately $31.2 million and primarily related to additions to property and equipment totaling approximately $31.7 million . Net cash used in investing activities was approximately $286.2 million for the year ended December 31, 2016 and was primarily related to $209.2 million for the WRC Acquisition, an investment in Laramie Energy of $55.0 million , and additions to property and equipment totaling approximately $24.8 million . Net cash used in investing activities was approximately $114.2 million for the year ended December 31, 2015 and was primarily related to $64.3 million for the Mid Pac acquisition, an investment in Laramie Energy of $27.5 million , and additions to property and equipment totaling approximately $22.3 million .

Net cash used in financing activities for the year ended December 31, 2017 was approximately $4.8 million and consisted primarily of proceeds from net borrowings and net repayments on our deferred payment arrangement of $10.7 million offset by deferred loan costs of $10.1 million and payments for early termination of financing agreements of $4.4 million . Net cash provided by financing activities for the year ended December 31, 2016 of approximately $190.1 million consisted primarily of proceeds from net borrowings and net borrowings on our deferred payment arrangement of $160.5 million and the sale of common stock totaling $49.0 million offset by a contingent consideration settlement of $12.0 million and deferred loan costs of $6.9 million . Net cash provided by financing activities for the year ended December 31, 2015 of approximately $60.4 million consisted primarily of proceeds from the sale of common stock totaling approximately $76.1 million and net proceeds from inventory financing agreements of $13.2 million , offset by net repayments of borrowings and deferred payment arrangement of $20.5 million and deferred loan costs of $7.3 million .

Capital Expenditures

Our capital expenditures, excluding acquisitions, for the year ended December 31, 2017 , totaled approximately $31.7 million and were primarily related to our retail segment, our Wyoming refining and logistics operations, and information technology systems. Our capital expenditure budget for 2018 ranges from $50 to $55 million and primarily relates to projects for the first phase of our hydrotreater construction to increase ultra-low sulfur distillate production capacity in our Hawaii refinery, our retail segment, and expansion projects at our Wyoming refinery.

We also continue to seek strategic investments in business opportunities, but the amount and timing of those investments are not predictable.

Contractual Obligations

We have various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly related to our operating activities. The following table summarizes our contractual obligations as of December 31, 2017 . Cash obligations reflected in the table below are not discounted.

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
			(in thousands)		
Long-term debt (including current portion)	$ 415,000	$ —	$ —	$ 115,000	$ 300,000
Interest payments on debt	205,304	29,000	58,000	49,135	69,169
Operating leases	80,682	16,453	20,954	13,607	29,668
Capital leases	1,789	863	870	56	—
Purchase commitments	506,687	506,340	282	65	—

Long-Term Debt (including Current Portion). Long-term debt includes the scheduled principal payments related to our outstanding debt obligations and letters of credit. Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for further discussion.

Interest Payments on Debt. Interest payments on debt represent estimated periodic interest payment obligations associated with our outstanding debt obligations using interest rates in effect as of December 31, 2017 . Please read Note 11—Debt to our consolidated financial statements under Item 8 of this Form 10-K for further discussion.

Operating Leases. Operating leases include minimum lease payment obligations associated with certain retail sites, office space, and office equipment leases. Also included in operating leases are charter agreements associated with our logistics operations.

Capital Leases. Capital leases include minimum lease payment obligations associated with certain retail sites and information technology systems.

Purchase Commitments. Purchase commitments primarily consist of contracts executed as of December 31, 2017 for the purchase of crude oil for use at our Hawaii refinery that are scheduled for delivery in 2018 .

Commitments and Contingencies

Supply and Offtake Agreements. On June 1, 2015, we entered into several agreements with J. Aron & Company ("J. Aron") to support the operations of our Hawaii refinery (the "Supply and Offtake Agreements"). On May 8, 2017 , we and J. Aron amended the Supply and Offtake Agreements and extended the term through May 31, 2021 with a one -year extension option upon mutual agreement of the parties. The Supply and Offtake Agreements were amended and restated on December 21, 2017 in connection with the issuance of the 7.75% Senior Secured Notes and the entry into the ABL Credit Facility . Please read Note 10—Inventory Financing Agreements to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Environmental Matters. Our petroleum refining operations and third-party oil and gas exploration and production operations in which we have a working interest are subject to extensive and periodically changing federal, state, and local environmental laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Many of these laws and regulations are becoming increasingly stringent and the cost of compliance can be expected to increase over time. Our policy is to accrue environmental and clean-up related costs of a non-capital nature when it is probable that a liability has been incurred and the amount can be reasonably estimated. Such estimates may be subject to revision in the future as regulations and other conditions change.

Periodically, we receive communications from various federal, state, and local governmental authorities asserting violations of environmental laws and/or regulations. These governmental entities may also propose or assess fines or require corrective actions for these asserted violations. We intend to respond in a timely manner to all such communications and to take appropriate corrective action. We do not anticipate that any such matters currently asserted will have a material impact on our financial condition, results of operations, or cash flows.

Regulation of Greenhouse Gases

The EPA has begun regulating GHG under the CAA . New construction or material expansions that meet certain GHG emissions thresholds will likely require that, among other things, a GHG permit be issued in accordance with the federal CAA regulations and we will be required in connection with such permitting to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce GHG emissions.

Furthermore, the EPA is currently developing refinery-specific GHG regulations and performance standards that are expected to impose GHG emission limits and/or technology requirements. These control requirements may affect a wide range of refinery operations. Any such controls could result in material increased compliance costs, additional operating restrictions for our business, and an increase in cost of the products we produce, which could have a material adverse effect on our financial position, results of operations, and liquidity.

On September 29, 2015, the EPA announced a final rule updating standards that control toxic air emissions from petroleum refineries, addressing, among other things, flaring operations, fenceline air quality monitoring, and additional emission reductions from storage tanks and delayed coking units. Affected existing sources will be required to comply with the new requirements no later than 2018, with certain refiners required to comply earlier depending on the relevant provision and refinery construction date. We do not anticipate that compliance with this rule will have a material impact on our financial condition, results of operations, or cash flows.

In 2007, the state of Hawaii passed Act 234, which required that GHG emissions be rolled back on a statewide basis to 1990 levels by the year 2020. Although delayed, the Hawaii Department of Health has issued regulations that would require each major facility to reduce CO_2 emissions by 16% by 2020 relative to a calendar year 2010 baseline (the first year in which GHG emissions were reported to the EPA under 40 CFR Part 98). Those rules are pending final approval by the Hawaii State Government. The Hawaii refinery's capacity to reduce fuel use and GHG emissions is limited. However, the state's pending regulation allows, and we anticipate the Hawaii refinery will be able to demonstrate, that additional reductions are not cost-effective or necessary in light of the state's current GHG inventory and future year projections. The pending regulation allows for "partnering" with other facilities (principally power plants) which have already dramatically reduced greenhouse emissions or are on schedule to reduce CO_2 emissions in order to comply with the state's Renewable Portfolio Standards.

Fuel Standards

In 2007, the U.S. Congress passed the Energy Independence and Security Act ("EISA") which, among other things, set a target fuel economy standard of 35 miles per gallon for the combined fleet of cars and light trucks in the U.S. by model year 2020 and contained a second Renewable Fuel Standard (the "RFS2"). In August 2012, the EPA and National Highway Traffic Safety Administration jointly adopted regulations that establish an average industry fuel economy of 54.5 miles per gallon by model year 2025. The RFS2 requires an increasing amount of renewable fuel usage, up to 36.0 billion gallons by 2022. In the near term, the RFS2 will be satisfied primarily with fuel ethanol blended into gasoline. The RFS2 may present production and logistics challenges for both the renewable fuels and petroleum refining and marketing industries in that we may have to enter into arrangements with other parties or purchase credits from the EPA to meet our obligations to use advanced biofuels, including biomass-based diesel and cellulosic biofuel, with potentially uncertain supplies of these new fuels.

In October 2010, the EPA issued a partial waiver decision under the federal CAA to allow for an increase in the amount of ethanol permitted to be blended into gasoline from 10% ("E10") to 15% ("E15") for 2007 and newer light duty motor vehicles. In January 2011, the EPA issued a second waiver for the use of E15 in vehicles model years 2001-2006. There are numerous issues, including state and federal regulatory issues, which need to be addressed before E15 can be marketed on a large scale for use in traditional gasoline engines. Consequently, qualified RINs will be required to fulfill the federal mandate for renewable fuels.

In March 2014, the EPA published a final Tier 3 gasoline standard that lowers the allowable sulfur level in gasoline to 10 parts per million ("ppm") and also lowers the allowable benzene, aromatics, and olefins content of gasoline. The effective date for the new standard is January 1, 2017, however, approved small volume refineries have until January 1, 2020 to meet the standard. Our Hawaii refinery is required to comply with Tier 3 gasoline standards within 30 months of June 21, 2016, the date our Hawaii refinery was disqualified from small volume refinery status. On March 19, 2015, the EPA confirmed the small refinery status of our Wyoming refinery.

Beginning on June 30, 2014, new sulfur standards for fuel oil used by marine vessels operating within 200 miles of the U.S. coastline (which includes the entire Hawaiian Island chain) was lowered from 10,000 ppm (1%) to 1,000 ppm (0.1%). The sulfur standards began at the Hawaii refinery and were phased in so that by January 1, 2015, they were to be fully aligned with the International Marine Organization ("IMO") standards and deadline. The more stringent standards apply universally to both U.S. and foreign flagged ships. Although the marine fuel regulations provided vessel operators with a few compliance options such as installation of on-board pollution controls and demonstration unavailability, many vessel operators will be forced to switch to a distillate fuel while operating within the Emission Control Area ("ECA"). Beyond the 200 mile ECA, large ocean vessels are still allowed to burn marine fuel with up to 3.5% sulfur. Our Hawaii refinery is capable of producing the 1% sulfur residual fuel oil that was previously required within the ECA. Although our Hawaii refinery remains in a position to supply vessels traveling to and through Hawaii, the market for 0.1% sulfur distillate fuel and 3.5% sulfur residual fuel is much more competitive.

There will be compliance costs and uncertainties regarding how we will comply with the various requirements contained in the EISA and other fuel-related regulations. We may experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

Wyoming Refinery

Our Wyoming refinery is subject to a number of consent decrees, orders, and settlement agreements involving the EPA and/or the Wyoming Department of Environmental Quality, some of which date back to the late 1970s and several of which remain in effect, requiring further actions at the Wyoming refinery. Please read Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Environmental Agreement

On September 25, 2013, Par Petroleum, LLC, Tesoro, and PHR entered into an Environmental Agreement ("Environmental Agreement"), which allocated responsibility for known and contingent environmental liabilities related to the acquisition of PHR , including the Consent Decree. Please read Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 and Legal Proceedings under Item 3 of this Form 10-K for more information.

Tesoro Earnout Dispute. On June 17, 2013, a wholly owned subsidiary of Par entered into a membership interest purchase agreement with Tesoro, pursuant to which it purchased all of the issued and outstanding membership interests in PHR . The PHR acquisition is subject to an earn-out provision during the years 2014-2016, subject to, among other things, an annual earn-out cap of $20 million . Please read Note 14—Commitments and Contingencies to our consolidated financial statements under Item 8 of this Form 10-K for more information.

Bankruptcy Matters. We emerged from the reorganization of Delta Petroleum Corporation ("Delta") on August 31, 2012 ("Emergence Date") when the plan of reorganization ("Plan") was consummated. Please read "Item 1. — Business — Bankruptcy and Plan of Reorganization" of this Form 10-K for more information.

Operating Leases. We have various cancelable and noncancelable operating leases related to land, vehicles, office, and retail facilities and other facilities used in the storage, transportation, and sale of crude oil and refined products. The majority of the future lease payments relate to retail stations and facilities used in the storage, transportation, and sale of crude oil and refined products. We have operating leases for most of our retail stations with an average term of 5 years remaining and generally containing renewal options and escalation clauses. Leases for facilities used in the storage, transportation, and sale of crude oil and refined products have various expiration dates extending to 2078 .

In addition, within our corporate and other and logistics segments, we have various agreements to lease storage facilities, towboats, barges, and other equipment. These leasing agreements have been classified as operating leases for financial reporting purposes and the related rental fees are charged to expense over the lease term as they become payable. The leases generally range in duration of five years or less and contain lease renewal options at fair value.

Minimum annual lease payments extending to 2078 for operating leases to which we are legally obligated and having initial or remaining noncancelable lease terms in excess of one year are as follows (in thousands):

2018	$	16,453
2019		12,305
2020		8,649
2021		7,332
2022		6,275
Thereafter		29,668
Total minimum rental payments	$	80,682

Capital Leases. We have capital lease obligations related primarily to the leases of five retail stations with remaining terms of two years and four five - year renewal options. Minimum annual lease payments including interest, for capital leases are as follows (in thousands):

2018	$	863
2019		703
2020		167
2021		56
2022		—
Thereafter		—
Total minimum lease payments	$	1,789
Less amount representing interest		86
Total minimum rental payments	$	1,703

Off-Balance Sheet Arrangements

Other than our operating leases, we have no off-balance sheet arrangements as of December 31, 2017 that are reasonably likely to have a current or future material affect on our financial condition, results of operations, or cash flows.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations were based on the consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these consolidated financial statements required us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, and expenses. Our significant accounting policies are described in Note 2—Summary of Significant Accounting Policies to our audited consolidated financial statements under Item 8 of this Form 10-K. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates on a periodic basis, including those related to fair value, impairments, natural gas and crude oil reserves, bad debts, natural gas and oil properties, income taxes, derivatives, contingencies, and litigation and base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Inventory

Inventories are stated at the lower of cost or net realizable value using the first-in, first-out accounting method. We value merchandise along with spare parts, materials, and supplies at average cost. Estimating the net realizable value of our inventory requires management to make assumptions about the timing of sales and the expected proceeds that will be realized for the sales.

Our refining segment acquires all of its crude oil utilized at the Hawaii refinery from J. Aron under procurement contracts. The crude oil remains in the legal title of J. Aron and is stored in our storage tanks governed by a storage agreement. Legal title to the crude oil passes to us at the tank outlet. After processing, J. Aron takes title to the refined products stored in our storage tanks until they are sold to our retail locations or to third parties. We record the inventory owned by J. Aron on our behalf as inventory with a corresponding accrued liability on our balance sheet because we maintain the risk of loss until the refined products are sold to third parties and we have an obligation to repurchase it. The valuation of our repurchase obligation requires that we make estimates of the prices and differentials assuming settlement at the end of the reporting period. Please read Note 10—Inventory Financing Agreements to our consolidated financial statements under Item 8 of this Form 10-K for additional information.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. In estimating fair value, we use discounted cash flow projections, recent comparable market transactions, if available, or quoted prices. We consider assumptions that third parties would make in estimating fair value, including the highest and best use of the asset. The assumptions used by another party could differ significantly from our assumptions.

We classify fair value balances based on the classification of the inputs used to calculate the fair value of a transaction. The inputs used to measure fair value have been placed in a hierarchy based on priority. The hierarchy gives the highest priority to unadjusted, readily observable quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Please read Note 13—Fair Value Measurements to our consolidated financial statements under Item 8 of this Form 10-K for additional information.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. We use a variety of methods to estimate the fair value of assets and liabilities acquired in business combinations and evaluating goodwill and other long-lived assets for impairment. These methods include the cost approach, the sales approach, and the income approach. These methods require management to make judgments regarding characteristics of the acquired property and future revenues and expenses. There is a significant amount of judgment involved in cash flow estimates. Changes in these estimates would result in different amounts allocated to the related assets and liabilities.

At December 31, 2015, we conducted an impairment test related to our equity investment in Laramie Energy . As a result of the decline in commodity prices during 2015, we concluded that our equity investment in Laramie Energy was impaired and recognized an other-than-temporary impairment charge of $41.1 million on our consolidated statement of operations for the year ended December 31, 2015. We primarily used a market approach to determine the fair value of our equity investment in Laramie Energy as of December 31, 2015. During 2017 and 2016, there was no impairment recorded in connection with our investment in Laramie Energy.

At September 30, 2015, we conducted an interim goodwill impairment test of our Texadian operations due to (i) a reduction in the forecasted results of operations during our annual budgeting process; (ii) the decision to cancel the charter on the barges used to move crude oil from Canada to the U.S. Gulf Coast due to lower forecasted commodity prices, and (iii) negative cash flows from the business during 2015. Upon completion of the goodwill impairment test, we determined the goodwill associated with the Texadian reporting unit was fully impaired resulting in a charge of $7.0 million in our consolidated statement of operations for the year ended December 31, 2015. In assessing the value of the reporting unit, we primarily used an income approach with a weighted-average discount rate of 15%.

We recognize assets acquired and liabilities assumed in business combinations at their estimated fair values as of the date of acquisition. The excess of the purchase price paid over the fair value of the identifiable assets acquired and liabilities assumed is allocated to goodwill. Significant judgment is required in estimating the fair value of assets acquired. We obtain the assistance of third-party valuation specialists in estimating fair values of tangible and intangible assets based on available historical information and on expectations and assumptions about the future, considering the perspective of marketplace participants.

Derivatives and Other Financial instruments. We are exposed to commodity price risk related to crude oil and refined products. We manage this exposure through the use of various derivative commodity instruments. These instruments include exchange traded futures and over-the-counter swaps, forwards, and options.

For our forward contracts that are derivatives, we have elected the normal purchase normal sale exclusion, as it is our policy to fulfill or accept the physical delivery of the product and we will not net settle. Therefore, we did not recognize the unrealized gains or losses related to these contracts in our consolidated financial statements. We apply the accrual method of accounting to contracts qualifying for the normal purchase and sales exemption.

All derivative instruments not designated as normal purchases or sales are recorded in the balance sheet as either assets or liabilities measured at their fair values. Changes in the fair value of these derivative instruments are recognized currently in earnings. We have not designated any derivative instruments as cash flow or fair value hedges and, therefore, do not apply hedge accounting treatment.

In addition, we may have other financial instruments, such as warrants or embedded debt features, that may be classified as liabilities when either (a) the holders possess rights to net cash settlement, (b) physical or net equity settlement is not in our control, or (c) the instruments contain other provisions that cause us to conclude that they are not indexed to our equity. We have accounted for our obligation to repurchase crude oil and refined products from J.Aron at the termination of the Supply and Offtake Agreements as an embedded derivative. Additionally, we have determined that the redemption option and the related make-whole premium on our 5.00% Convertible Senior Notes represent an embedded derivative. These liabilities were initially recorded at fair value and subsequently adjusted to fair value at the end of each reporting period through earnings.

Asset Retirement Obligations. We record asset retirement obligations ("AROs") at fair value in the period in which we have a legal obligation, whether by government action or contractual arrangement, to incur these costs and can make a reasonable estimate of the fair value of the liability. Our AROs arise from our refining, retail, and logistics operations, as well as plugging and abandonment of wells within our natural gas and crude oil operations. AROs are calculated based on the present value of the estimated removal and other closure costs using our credit-adjusted risk-free rate. When the liability is initially recorded, we capitalize the cost by increasing the book value of the related long-lived tangible asset. The liability is accreted to its estimated settlement value and the related capitalized cost is depreciated over the asset's useful life. Both expenses are recorded in Depreciation, depletion, and amortization in the consolidated statements of operations. The difference between the settlement amount and the recorded liability is recorded as a gain or loss on asset disposals in our consolidated statements of operations. We estimate settlement dates by considering our past practice, industry practice, management's intent, and estimated economic lives.

We cannot currently estimate the fair value for certain AROs primarily because we cannot estimate settlement dates (or ranges of dates) associated with these assets. These AROs include hazardous materials disposal (such as petroleum manufacturing by-products, chemical catalysts, and sealed insulation material containing asbestos) and removal or dismantlement requirements associated with the closure of our refining facilities, terminal facilities, or pipelines, including the demolition or removal of certain major processing units, buildings, tanks, pipelines, or other equipment.

Environmental Matters

We capitalize environmental expenditures that extend the life or increase the capacity of facilities as well as expenditures that prevent environmental contamination. We expense costs that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation. We record liabilities when environmental assessments and/or remedial efforts are probable and can be reasonably estimated. Cost estimates are based on the expected timing and extent of remedial actions required by governing agencies, experience gained from similar sites for which environmental assessments or remediation have been completed, and the amount of our anticipated liability considering the proportional liability and financial abilities of other responsible parties. Usually, the timing of these accruals coincides with the completion of a feasibility study or our commitment to a formal plan of action. Estimated liabilities are not discounted to present value and are presented within Other liabilities on our consolidated balance sheets. Environmental expenses are recorded in Operating expenses on our consolidated statements of operations.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our earnings, cash flow, and liquidity are significantly affected by commodity price volatility. Our Revenues fluctuate with refined product prices and our Cost of revenues (excluding depreciation) fluctuates with movements in crude oil and feedstock prices. Assuming all other factors remain constant, a $1 per barrel change in average gross refining margins, based on our throughput of 87 thousand barrels per day for the fourth quarter of 2017 , would change annualized operating income by approximately $31.2 million . This analysis may differ from actual results.

In order to manage commodity price risks, we utilize exchange traded futures, options, and over-the-counter ("OTC") swaps to manage commodity price risks associated with:

- the price for which we sell our refined products;
- the price we pay for crude oil and other feedstocks;
- our crude oil and refined products inventory; and
- our fuel requirements for our Hawaii refinery.

Our Supply and Offtake Agreements with J.Aron require us to hedge our exposure based on the time spread between the crude oil cargo pricing period and the expected delivery month. We manage this exposure by entering into swaps with J.Aron.

Please read Note 10—Inventory Financing Agreements to our consolidated financial statements under Item 8 of this Form 10-K for more information.

All of our futures and OTC swaps are executed to economically hedge our physical commodity purchases, sales, and inventory. Our open futures and OTC swaps expire at various dates through December 30, 2018. At December 31, 2017 , these open commodity derivative contracts represent:

- futures sales contracts of 200 thousand barrels that economically hedge our crude oil and refined product inventory;
- OTC swap purchases of 321 thousand barrels that economically hedge our crude oil and refined products month-end target inventory under our Supply and Offtake Agreements;
- net OTC swaps and futures sales contracts of 140 thousand barrels that economically hedge our sales of refined products; and
- option collars of 60 thousand barrels per month and OTC swaps of 15 thousand barrels per month through December 2018 that economically hedge our internally consumed fuel.

Based on our swaps and futures at December 31, 2017 , a $1 change in the price of crude oil, assuming all other factors remain constant, would result in an immaterial change to the fair value of our derivative instruments and cost of revenues.

Our predominant variable operating cost is the cost of fuel consumed in the refining process, which is included in Cost of revenues (excluding depreciation) on our consolidated statements of operations. Assuming normal operating conditions, we consume approximately 74 thousand barrels per day of crude oil during the refining process at our Hawaii refinery. We internally consume approximately 3% of this throughput in the refining process which is accounted for as a fuel cost. We have economically hedged our internally consumed fuel cost at our Hawaii refinery by purchasing option collars and swaps. These option collars have a weighted-average strike price ranging from a floor of $37.49 per barrel to a ceiling of $68.33 per barrel. The OTC swaps have a weighted-average price of $46.45 . We do not economically hedge our internally consumed fuel cost at our Wyoming refinery.

Compliance Program Price Risk

We are exposed to market risks related to the volatility in the price of RINs required to comply with the Renewable Fuel Standard. Our overall RINs obligation is based on a percentage of our domestic shipments of on-road fuels as established by the EPA. To the degree we are unable to blend the required amount of biofuels to satisfy our RINs obligation, we must purchase RINs on the open market. To mitigate the impact of this risk on our results of operations and cash flows, we may purchase RINs when the price of these instruments is deemed favorable. Some of these contracts are derivative instruments, however, we elect the normal purchases normal sales exception and do not record these contracts at their fair values.

Interest Rate Risk

As of December 31, 2017 , we had no outstanding debt that was subject to floating interest rates. We did have interest rate exposure in connection with our liability under the J. Aron Supply and Offtake Agreements for which we pay a charge based on three-month LIBOR. An increase of 1% in the variable rate on our indebtedness, after considering the instruments subject to minimum interest rates, would result in an increase to our Cost of revenues (excluding depreciation) and Interest expense and financing costs, net of approximately $2.7 million and $0.3 million per year, respectively.

We utilize interest rate swaps, interest rate caps, interest rate collars, or other similar contracts to manage our interest rate risk. As of December 31, 2017 , we had locked in an average fixed rate of 1.1% in exchange for a floating interest rate indexed to the three-month LIBOR on an aggregate notional amount of $200.0 million . The interest rate swaps mature in February 2019 and March 2021.

Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. We will continue to closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with our credit policy.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements and schedule required by this item are set forth beginning on page F-1.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are designed with the objective of ensuring that all information required to be disclosed in our reports filed under the Securities Exchange Act of 1934, as amended ("Exchange Act"), such as this report, is recorded, processed, summarized, and reported within the time periods specified by the SEC. In connection with the preparation of this Annual Report on Form 10-K, as of December 31, 2017 , an evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures were effective as of December 31, 2017 .

Changes in Internal Control over Financial Reporting

There were no changes during the quarter ended December 31, 2017 in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financing reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management 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 system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management 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 (COSO) in Internal Control—Integrated Framework (2013). Based on our assessment we believe that, as of December 31, 2017 , the Company's internal control over financial reporting is effective based on those criteria.

Deloitte & Touche LLP, the Company's independent registered public accounting firm that audited the Company's financial statements included in this Annual Report on Form 10-K, has issued an audit report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2017 , which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Par Pacific Holdings, Inc.
Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Par Pacific Holdings, Inc. and subsidiaries (the "Company") 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). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017 of the Company and our report dated March 12, 2018 expressed an unqualified opinion on those financial statements.

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 the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit 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, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2018

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this item is incorporated in this Annual Report on Form 10-K by reference to our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the Securities and Exchange Commission not later than 120 days after the end of the fiscal year ended December 31, 2017 .

Item 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated in this Annual Report on Form 10-K by reference to our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the Securities and Exchange Commission not later than 120 days after the end of the fiscal year ended December 31, 2017 .

Item 12.SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated in this Annual Report on Form 10-K by reference to our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the Securities and Exchange Commission not later than 120 days after the close of our fiscal year ended December 31, 2017 .

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated in this Annual Report on Form 10-K by reference to our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the Securities and Exchange Commission not later than 120 days after the end of the fiscal year ended December 31, 2017 .

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated in this Annual Report on Form 10-K by reference to our definitive proxy statement or an amendment to this Annual Report on Form 10-K to be filed with the Securities and Exchange Commission not later than 120 days after the end of the fiscal year ended December 31, 2017 .

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

(1) Consolidated Financial Statements (Included under Item 8). The Index to the Consolidated Financial Statements is included on page F-1 of this annual report on Form 10-K and is incorporated herein by reference.

(2) Financial Statement Schedules

Schedule I – Condensed Financial Information of Registrant

(b) Index to Exhibits

2.1	Third Amended Joint Chapter 11 Plan of Reorganization of Delta Petroleum Corporation and Its Debtor Affiliates dated August 16, 2012. Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on September 7, 2012.**
2.2	Contribution Agreement, dated as of June 4, 2012, among Piceance Energy, LLC, Laramie Energy, LLC and the Company. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 8, 2012.**
2.3	Membership Interest Purchase Agreement dated as of June17, 2013, by and among Tesoro Corporation, Tesoro Hawaii, LLC and Hawaii Pacific Energy, LLC Incorporated by reference to Exhibit 2.4 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013, filed on August 14, 2013.**
2.4	Agreement and Plan of Merger dated as of June 2, 2014, by and among the Company, Bogey, Inc., Koko'oha Investments, Inc., and Bill D. Mills, in his capacity as the Shareholders' Representative. Incorporated by reference to Exhibit 2.5 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed on August 11, 2014.**
2.5	Amendment of Agreement and Plan of Merger dated as of September 9, 2014, by and among the Company, Bogey, Inc., Koko'oha Investments, Inc. and Bill D. Mills, in his capacity as the Shareholders' Representative. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on September 10, 2014.**
2.6	Second Amendment of Agreement and Plan of Merger dated as of December 31, 2014, by and among Par Petroleum Corporation, Bogey, Inc., Koko'oha Investments, Inc. and Bill D. Mills, in his capacity as the Shareholder's Representative. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 7, 2015.**
2.7	Third Amendment to Agreement and Plan of Merger dated as of March 31, 2015, by and among the Company, Bogey, Inc., Koko'oha Investments, Inc. and Bill D. Mills, in his capacity as the Shareholders' Representative. Incorporated by reference to Exhibit 2.4 to the Company's Current Report on Form 8-K filed on April 2, 2015.**
2.8	Unit Purchase Agreement, dated as of June 13, 2016, between Par Wyoming, LLC and Black Elk Refining, LLC. Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed on June 15, 2016.**
2.9	First Amendment to Unit Purchase Agreement dated as of July 14, 2016, between Par Wyoming, LLC and Black Elk Refining, LLC. Incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K filed on July 15, 2016.**
3.1	Restated Certificate of Incorporation of the Company dated October 20, 2015. Incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on October 20, 2015.
3.2	Second Amended and Restated Bylaws of the Company dated October 20, 2015. Incorporated by reference to Exhibit 3.3 to the Company's Current Report on Form 8-K filed on October 20, 2015.
4.1	Form of the Company's Common Stock Certificate. Incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K filed on March 31, 2014.

4.2	Registration Rights Agreement effective as of August 31, 2012, by and among the Company, Zell Credit Opportunities Master Fund, L.P., Waterstone Capital Management, L.P., Pandora Select Partners, LP, Iam Mini-Fund 14 Limited, Whitebox Multi-Strategy Partners, LP, Whitebox Credit Arbitrage Partners, LP, HFR RVA Combined Master Trust, Whitebox Concentrated Convertible Arbitrage Partners, LP and Whitebox Asymmetric Partners, LP. Incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K filed on September 7, 2012.
4.3	Warrant Issuance Agreement dated as of August 31, 2012, by and among the Company and WB Delta, Ltd., Waterstone Offshore ER Fund, Ltd., Prime Capital Master SPC, Waterstone Market Neutral MAC51, Ltd., Waterstone Market Neutral Master Fund, Ltd., Waterstone MF Fund, Ltd., Nomura Waterstone Market Neutral Fund, ZCOF Par Petroleum Holdings, L.L.C. and Highbridge International, LLC. Incorporated by reference to Exhibit 4.4 to the Company's Current Report on Form 8-K filed on September 7, 2012.
4.4	Form of Common Stock Purchase Warrant dated as of June 4, 2012. Incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed on September 7, 2012.
4.5	Par Pacific Holdings, Inc. Amended and Restated 2012 Long Term Incentive Plan. Incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A filed on April 21, 2016.****
4.6	Registration Rights Agreement dated as of September 25, 2013, by and among the Company and the Purchasers party thereto. Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 27, 2013.
4.7	Stockholders Agreement dated April 10, 2015. Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on April 13, 2015.
4.8	Registration Rights Agreement, dated June 21, 2016, between Par Pacific Holdings, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the Initial Purchasers. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 22, 2016.
4.9	Registration Rights Agreement dated as of July 14, 2016, by and among Par Pacific Holdings, Inc. and the purchasers party thereto. Incorporated by Reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on July 15, 2016.
4.10	First Amendment to Registration Rights Agreement dated as of September 27, 2016, by and among the Company and the purchasers party thereof. Incorporated by reference to Exhibit 4.14 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.11	Second Amendment to Registration Rights Agreement dated as of September 30, 2016, by and among the Company and the holders party thereto. Incorporated by reference to Exhibit 4.15 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.12	Third Amendment to Registration Rights Agreement dated as of October 7, 2016, by and among the Company and the holders party thereto. Incorporated by reference to Exhibit 4.16 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.13	Fourth Amendment to Registration Rights Agreement dated as of October 14, 2016, by and among the Company and the holders party thereto. Incorporated by reference to Exhibit 4.17 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.14	Fifth Amendment to Registration Rights Agreement dated as of October 21, 2016, by and among the Company and the holders party thereto. Incorporated by reference to Exhibit 4.18 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.15	Sixth Amendment to Registration Rights Agreement dated as of October 28, 2016 by and among the Company and the holders party thereto. Incorporated by reference to Exhibit 4.19 to the Company's Quarterly Report on Form 10-Q filed on November 4, 2016.
4.16	Indenture, dated June 21, 2016, between Par Pacific Holdings, Inc. and Wilmington Trust, National Association, as Trustee. Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on June 22, 2016.
4.17	Indenture, dated December 21, 2017, among Par Petroleum, LLC, Par Petroleum Finance Corp., the Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee and Collateral Trustee. Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed on December 22, 2017.

10.1	Loan and Security Agreement dated as of December 21, 2017, among Par Petroleum, LLC, Par Hawaii, Inc, Mid Pac Petroleum, LLC, HIE Retail, LLC, Hermes Consolidated, LLC, Wyoming Pipeline Company, LLC, and the other members party thereto, the financial institutions party thereto, and Bank of America, N.A., as administrative agent. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 22, 2017.
10.2	Third Amended and Restated Limited Liability Company Agreement of Laramie Energy, LLC dated February 22, 2016, by and among Laramie Energy II, LLC, Par Piceance Energy Equity LLC and the other members party thereto. Incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 3, 2016.**
10.3	Credit Agreement dated as of June 4, 2012 among Piceance Energy, LLC, the financial institutions party thereto, JPMorgan Chase Bank, N.A., as administrative agent and Wells Fargo Bank, National Association, as syndication agent. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.4	First Amendment to Credit Agreement dated August 31, 2012, by and among Piceance Energy, LLC, the financial institutions party thereto and JPMorgan Chase Bank, N.A. Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.5	Delta Petroleum General Recovery Trust Agreement dated August 27, 2012, by and among the Company, DPCA LLC, Delta Exploration Company, Inc., Delta Pipeline, LLC, DLC, Inc., CEC, Inc., Castle Texas Production Limited. Partnership, Amber Resources Company of Colorado, Castle Exploration Company, Inc. and John T. Young. Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.6	Pledge Agreement dated August 31, 2012, by Par Piceance Energy Equity LLC in favor of Jefferies Finance LLC. Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.7	Intercreditor Agreement dated August 31, 2012, by and among JP Morgan Chase Bank, N.A., as administrative agent for the First Priority Secured Parties (as defined therein), Jefferies Finance LLC, as administrative agent for the Second Priority Secured Parties (as defined therein), the Company and Par Piceance Energy Equity LLC. Incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.8	Pledge and Security Agreement, dated August 31, 2012, by the Company and certain of its subsidiaries in favor of Jefferies Finance LLC. Incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed on September 7, 2012.
10.9	Form of Indemnification Agreement between the Company and its Directors and Executive Officers. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 19, 2012.****
10.10	Letter Agreement dated as of September 17, 2013 but effective as of January 1, 2013, by and between Equity Group Investments and the Company. Incorporated by reference to Exhibit 10.17 to the Company's Quarterly Report on Form 10-Q filed on November 14, 2013.
10.11	Environmental Agreement dated as of September 25, 2013, by and among Tesoro Corporation, Tesoro Hawaii, LLC and Hawaii Pacific Energy, LLC. Incorporated by reference to Exhibit 10.16 to the Company's Quarterly Report on Form 10-Q filed on November 14, 2013.
10.12	Employment Offer Letter with William Monteleone dated September 25, 2013. Incorporated by reference to Exhibit 10.43 to the Company's Amendment No. 3 to Annual Report on Form 10-K/A filed on July 2, 2014.****
10.13	Award Notice of Restricted Stock with William Monteleone dated December 31, 2012. Incorporated by reference to Exhibit 10.46 to the Company's Amendment No. 3 to Annual Report on Form 10-K/A filed on July 2, 2014.****
10.14	Award Notice of Restricted Stock with William Monteleone dated September 25, 2013. Incorporated by reference to Exhibit 10.47 to the Company's Amendment No. 3 to Annual Report on Form 10-K/A filed on July 2, 2014.****
10.15	Employment Offer Letter with Joseph Israel dated December 12, 2014. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on December 17, 2014.****
10.16	Award Notice of Restricted Stock with Joseph Israel dated January 5, 2015. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 7, 2015.****
10.17	Nonstatutory Stock Option Agreement with Joseph Israel dated January 5, 2015. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on January 7, 2015.****
10.18	Employment Offer Letter with James Matthew Vaughn dated July 3, 2014. Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2016.****

10.19	Initial Award with James Matthew Vaughn dated November 5, 2014. Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2016.****
10.20	Stock Award with James Matthew Vaughn dated July 3, 2015. Incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2016.****
10.21	Employment Offer Letter with Jim Yates dated March 10, 2015. Incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2016.****
10.22	Initial Award with Jim Yates dated May 8, 2015. Incorporated by reference to Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q filed on May 5, 2016.****
10.23	Restricted Stock Award between Par Pacific Holdings, Inc. and William Monteleone dated February 16, 2016. Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.24	Stock Option Award between Par Pacific Holdings, Inc. and William Monteleone dated February 16, 2016. Incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.25	Restricted Stock Award between Par Pacific Holdings, Inc. and James Matthew Vaughn dated February 16, 2016. Incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.26	Stock Option Award between Par Pacific Holdings, Inc. and James Matthew Vaughn dated February 16, 2016. Incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.27	Restricted Stock Award between Par Pacific Holdings, Inc. and Jim Yates dated February 16, 2016. Incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.28	Stock Option Award between Par Pacific Holdings, Inc. and Jim Yates dated February 16, 2016. Incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q filed on August 9, 2016.****
10.29	Third Amendment to Delayed Draw Term Loan and Bridge Credit Agreement dated as of March 11, 2015, by and among the Company, the Guarantors party thereto, the Term Lenders party thereto and Jefferies Finance LLC, as administrative agent for the Lenders. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 12, 2015.
10.30	Credit Agreement dated as of April 1, 2015, by and among Koko'oha Investments, Inc., Mid Pac Petroleum, LLC, Bank of Hawaii and the other lenders party thereto, and Bank of Hawaii, as administrative agent. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 2, 2015.
10.31	Pledge Agreement dated as of April 1, 2015, by Hawaii Pacific Energy, LLC in favor of Jefferies Finance LLC. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 2, 2015.
10.32	Limited Recourse Guaranty dated as of April 1, 2015, by Hawaii Pacific Energy, LLC. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on April 2, 2015.
10.33	Fourth Amendment to Delayed Draw Term Loan and Bridge Loan Credit Agreement dated as of April 1, 2015, by and among the Company, the Guarantors party thereto, the Term Lenders party thereto and Jefferies Finance LLC, as administrative agent for the lenders. Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on April 2, 2015.
10.34	First Amendment to Credit Agreement dated as of March 30, 2015 among HIE Retail, LLC, Bank of Hawaii, American Savings Bank, F.S.B. and Central Pacific Bank, and Bank of Hawaii, as administrative and collateral agent for the Lenders. Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on April 2, 2015.
10.35	Form of Award of Restricted Stock (Discretionary Long Term Incentive Plan). Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 2, 2015.****
10.36	Form of Award of Restricted Stock Units (Discretionary Long Term Incentive Plan). Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on April 2, 2015.****
10.37	Form of Nonstatutory Stock Option Agreement (Discretionary Long Term Incentive Plan). Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed on April 2, 2015.****

10.38	Termination of Stockholders Agreement dated April 10, 2015 by and among Par Petroleum Corporation, Zell Credit Opportunities Fund, L.P., ZCOF Par Petroleum Holdings, LLC, Pandora Select Partners, LP, Whitebox Multi-Strategy Partners, LP, Whitebox Credit Arbitrage Partners, LP, Whitebox Concentrated Convertible Arbitrage Partners, LP, and Whitebox Asymmetric Partners, LP. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 13, 2015.
10.39	Par Petroleum (and subsidiaries) Incentive Compensation Plan. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 12, 2015.****
10.40	Amended and Restated Supply and Offtake Agreement dated as of December 21, 2017, between Par Hawaii Refining, LLC and J. Aron & Company, LLC. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on December 22, 2017.
10.41	Storage Facilities Agreement dated as of June 1, 2015, between Hawaii Independent Energy, LLC and J. Aron & Company. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed June 2, 2015.
10.42	Marketing and Sales Agreement dated as of June 1, 2015, between Hawaii Independent Energy, LLC and J. Aron & Company. Incorporated as Exhibit 10.3 to the Company's Current Report on Form 8-K filed June 2, 2015.
10.43	Amended and Restated Pledge and Security Agreement dated as of December 21, 2017, between Par Hawaii Refining, LLC and J. Aron & Company, LLC. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on December 22, 2017.
10.44	Environmental Indemnity Agreement dated as of June 1, 2015, by Hawaii Independent Energy, LLC in favor of J. Aron & Company. Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed June 2, 2015.
10.45	Employment Offer Letter with William C. Pate dated October 12, 2015. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 14, 2015.****
10.46	Initial Award with William C. Pate dated October 12, 2015. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed October 14, 2015.****
10.47	Amendment to Employment Offer Letter with Joseph Israel dated October 12, 2015. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed October 14, 2015.****
10.48	Unit Purchase Agreement dated February 22, 2016, by and among Laramie Energy, LLC, Par Piceance Energy Equity LLC, and the other parties thereto. Incorporated by reference to Exhibit 10.74 to the Company's Annual Report on Form 10-K filed on March 3, 2016.**
10.49	Equity Commitment Letter dated December 17, 2015, by and between Par Pacific Holdings, Inc. and Piceance Energy, LLC. Incorporated by reference to Exhibit 10.75 to the Company's Annual Report on Form 10-K filed on March 3, 2016.**
10.50	First Amendment to Third Amended and Restated Loan Agreement dated as of March 31, 2016, by and among Hermes Consolidated, LLC, Wyoming Pipeline Company LLC, Par Wyoming, LLC and Bank of America, N.A. Incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed July 15, 2016.
10.51	Second Amendment to Third Amended and Restated Loan Agreement dated as of May 25, 2016, by and among Hermes Consolidated, LLC, Wyoming Pipeline Company LLC, Par Wyoming, LLC and Bank of America, N.A. Incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed July 15, 2016.
10.52	Third Amendment to Third Amended and Restated Loan Agreement dated as of July 14, 2016, by and among Hermes Consolidated, LLC, Wyoming Pipeline Company LLC, Par Wyoming, LLC and Bank of America, N.A. Incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed July 15, 2016.
10.53	Fourth Amendment to Third Amended and Restated Loan Agreement dated as of July 14, 2016, by and among Hermes Consolidated, LLC, Wyoming Pipeline Company LLC, Par Wyoming, LLC and Bank of America, N.A. Incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed July 15, 2016.
10.54	Note Purchase Agreement dated as of July 14, 2016, by and among Par Pacific Holdings, Inc. and the purchasers named therein. Incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed July 15, 2016.
10.55	Par Pacific Holdings, Inc. Non-Qualified Deferred Compensation Plan. Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 6, 2017.****
10.56	Par Pacific Holdings, Inc. Severance Plan for Senior Officers. Incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 6, 2017. ****

12.1	Statement of Computation of Ratio of Earnings to Fixed Charges.*
14.1	Par Pacific Holdings, Inc. Code of Business Conduct and Ethics for Employees, Executive Officers and Directors, effective December 3, 2015. Incorporated by reference to Exhibit 14.1 to the Company's Annual Report on Form 10-K filed March 3, 2016.
21.1	Subsidiaries of the Registrant.*
23.1	Consent of Deloitte & Touche LLP*
23.2	Consent of Deloitte & Touche LLP related to the financial statements of Laramie Energy, LLC.*
23.3	Consent of Netherland, Sewell & Associates, Inc.*
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.*
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350.*
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350.*
99.1	Report of Netherland, Sewell & Associates, Inc. regarding the registrants Proved Reserves as of December 31, 2017.*
99.2	Laramie Energy, LLC Financial Statements and Independent Auditors' Report, as of December 31, 2017 and 2016, and for the years ended December 31, 2017, 2016, and 2015.*
101.INS	XBRL Instance Document.***
101.SCH	XBRL Taxonomy Extension Schema Documents.***
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.***
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.***
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.***
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.***

*	Filed herewith.
**	Schedules and similar attachments have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish supplementally a copy of any omitted schedule or similar attachment to the Securities and Exchange Commission upon request.
***	These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended and otherwise are not subject to liability under those sections.
****	Management contract or compensatory plan or arrangement.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2017, 2016, and 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Par Pacific Holdings, Inc.
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Par Pacific Holdings, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016 , the related consolidated statements of operations, comprehensive income (loss), cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2017 , and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 , in conformity with accounting principles generally accepted in the United States of America.

We have also 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 and our report dated March 12, 2018 , expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's 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 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2018

We have served as the Company's auditor since 2013.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share and per share data)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 118,333	$ 47,772
Restricted cash	744	1,246
Trade accounts receivable	121,831	102,384
Inventories	345,357	198,326
Prepaid and other current assets	17,279	53,380
Total current assets	603,544	403,108
Property and equipment		
Property, plant, and equipment	529,238	499,867
Proved oil and gas properties, at cost, successful efforts method of accounting	400	1,122
Total property and equipment	529,638	500,989
Less accumulated depreciation and depletion	(79,622)	(49,727)
Property and equipment, net	450,016	451,262
Long-term assets		
Investment in Laramie Energy, LLC	127,192	108,823
Intangible assets, net	26,604	29,912
Goodwill	107,187	105,732
Other long-term assets	32,864	46,596
Total assets	$ 1,347,407	$ 1,145,433
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ —	$ 20,286
Obligations under inventory financing agreements	363,756	225,135
Accounts payable	52,543	65,190
Advances from customers	9,522	23,774
Accrued taxes	17,687	13,194
Other accrued liabilities	27,444	35,186
Total current liabilities	470,952	382,765
Long-term liabilities		
Long-term debt, net of current maturities	384,812	350,110
Common stock warrants	6,808	5,134
Long-term capital lease obligations	1,220	1,780
Other liabilities	35,896	36,735
Total liabilities	899,688	776,524
Commitments and contingencies (Note 14)		
Stockholders' equity		
Preferred stock, $0.01 par value: 3,000,000 shares authorized, none issued	—	—
Common stock, $0.01 par value; 500,000,000 shares authorized at December 31, 2017 and December 31, 2016, 45,776,087 shares and 45,533,913 shares issued at December 31, 2017 and December 31, 2016, respectively	458	455
Additional paid-in capital	593,295	587,057
Accumulated deficit	(148,178)	(220,799)
Accumulated other comprehensive income	2,144	2,196
Total stockholders' equity	447,719	368,909
Total liabilities and stockholders' equity	$ 1,347,407	$ 1,145,433

See accompanying notes to consolidated financial statements.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2017	**2016**	**2015**
Revenues	$ 2,443,066	$ 1,865,045	$ 2,066,337
Operating expenses			
Cost of revenues (excluding depreciation)	2,054,627	1,636,339	1,787,368
Operating expense (excluding depreciation)	202,019	166,216	141,621
Depreciation, depletion, and amortization	45,989	31,617	19,918
Impairment expense	—	—	9,639
General and administrative expense (excluding depreciation)	46,078	42,073	44,271
Acquisition and integration expense	395	5,294	2,006
Total operating expenses	2,349,108	1,881,539	2,004,823
Operating income (loss)	93,958	(16,494)	61,514
Other income (expense)			
Interest expense and financing costs, net	(31,632)	(28,506)	(20,156)
Loss on termination of financing agreements	(8,633)	—	(19,669)
Other income (expense), net	914	(98)	(291)
Change in value of common stock warrants	(1,674)	2,962	(3,664)
Change in value of contingent consideration	—	10,770	(18,450)
Equity earnings (losses) from Laramie Energy, LLC	18,369	(22,381)	(55,983)
Total other income (expense), net	(22,656)	(37,253)	(118,213)
Income (loss) before income taxes	71,302	(53,747)	(56,699)
Income tax benefit	1,319	7,912	16,788
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Income (loss) per share			
Basic	$ 1.58	$ (1.08)	$ (1.06)
Diluted	$ 1.57	$ (1.08)	$ (1.06)
Weighted-average number of shares outstanding			
Basic	45,543	42,349	37,678
Diluted	45,583	42,349	37,678

See accompanying notes to consolidated financial statements.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Other comprehensive income (loss):			
Reclassification of other post-retirement benefits loss to net income	—	—	1,082
Other post-retirement benefits income (loss), net of tax	(52)	2,196	(636)
Total other comprehensive income (loss), net of tax	(52)	2,196	446
Comprehensive income (loss)	$ 72,569	$ (43,639)	$ (39,465)

See accompanying notes to consolidated financial statements.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities:			
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:			
Depreciation, depletion, and amortization	45,989	31,617	19,918
Impairment expense	—	—	9,639
Loss on termination of financing agreements	8,633	—	19,669
Gain on termination of other post-retirement benefits	—	—	(5,550)
Non-cash interest expense	7,276	18,121	12,449
Change in value of common stock warrants	1,674	(2,962)	3,664
Change in value of contingent consideration	—	(10,770)	18,450
Deferred taxes	(1,321)	(7,935)	(16,489)
Stock-based compensation	7,204	6,625	5,165
Unrealized (gain) loss on derivative contracts	(989)	(15,479)	10,896
Equity (earnings) losses from Laramie Energy, LLC	(18,369)	22,381	55,983
Net changes in operating assets and liabilities:			
Trade accounts receivable	(19,100)	(17,162)	54,529
Collateral posted with broker for derivative transactions	2,499	18,212	(20,927)
Prepaid and other assets	37,645	447	(35,697)
Inventories	(146,533)	49,015	31,913
Deferred turnaround expenditures	—	(32,661)	—
Obligations under inventory financing agreements	143,034	(5,977)	34,845
Accounts payable and other accrued liabilities	(33,780)	(26,698)	(26,188)
Contingent consideration	—	(4,830)	—
Net cash provided by (used in) operating activities	106,483	(23,891)	132,358
Cash flows from investing activities:			
Acquisitions of businesses, net of cash acquired	—	(209,183)	(64,331)
Capital expenditures	(31,708)	(24,833)	(22,345)
Proceeds from sale of assets	35	2,773	—
Change in restricted cash	502	—	—
Investment in Laramie Energy, LLC	—	(55,000)	(27,529)
Net cash used in investing activities	(31,171)	(286,243)	(114,205)
Cash flows from financing activities:			
Proceeds from sale of common stock, net of offering costs	—	49,044	76,056
Proceeds from borrowings	616,706	354,682	208,158
Repayments of borrowings	(603,770)	(202,165)	(227,212)
Net borrowings (repayments) on deferred payment arrangement	(2,198)	8,027	(1,436)
Payment of deferred loan costs	(10,064)	(6,892)	(7,335)
Contingent consideration settlements	—	(11,980)	—
Proceeds from inventory financing agreements	—	—	271,000
Payments for termination of supply and exchange agreements	—	—	(257,811)
Payments for early termination of financing agreements	(4,432)	—	—
Other financing activities, net	(993)	(598)	(995)
Net cash provided by (used in) financing activities	(4,751)	190,118	60,425
Net increase (decrease) in cash and cash equivalents	70,561	(120,016)	78,578
Cash and cash equivalents at beginning of period	47,772	167,788	89,210
Cash and cash equivalents at end of period	$ 118,333	$ 47,772	$ 167,788
Supplemental cash flow information:			

Net cash received (paid) for:						
Interest	$	(23,873)	$	(13,217)	$	(6,891)
Taxes		(1,478)		589		402
Non-cash investing and financing activities:						
Accrued capital expenditures	$	2,926	$	4,907	$	2,102
Value of warrants and debt reclassified to equity		—		3,084		7,691
Capital lease additions		165		1,575		216

See accompanying notes to consolidated financial statements.

PAR PACIFIC HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock		Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income	Total Equity
	Shares	Amount				
Balance, January 1, 2015	37,069	$ 371	$ 427,287	$ (135,053)	$ (446)	$ 292,159
Issuance of common stock, net of offering costs of $1.0 million	3,500	35	76,021	—	—	76,056
Exercise of common stock warrants	404	4	7,726	—	—	7,730
Stock-based compensation	98	1	5,164	—	—	5,165
Purchase of common stock for retirement	(61)	(1)	(1,033)	—	—	(1,034)
Other comprehensive income	—	—	—	—	446	446
Net loss	—	—	—	(39,911)	—	(39,911)
Balance, December 31, 2015	41,010	410	515,165	(174,964)	—	340,611
Issuance of common stock, net of offering costs of $1.0 million	4,075	41	49,003	—	—	49,044
Stock-based compensation	218	3	6,622	—	—	6,625
Equity component of 5.00% Convertible Senior Notes due 2021, net of tax of $8.6 million	—	—	13,526	—	—	13,526
Conversion of Bridge Notes	273	2	3,338	—	—	3,340
Purchase of common stock for retirement	(42)	(1)	(597)	—	—	(598)
Other comprehensive income	—	—	—	—	2,196	2,196
Net loss	—	—	—	(45,835)	—	(45,835)
Balance, December 31, 2016	45,534	455	587,057	(220,799)	2,196	368,909
Stock-based compensation	303	4	7,200	—	—	7,204
Purchase of common stock for retirement	(61)	(1)	(962)	—	—	(963)
Other comprehensive loss	—	—	—	—	(52)	(52)
Net income	—	—	—	72,621	—	72,621
Balance, December 31, 2017	45,776	$ 458	$ 593,295	$ (148,178)	$ 2,144	$ 447,719

See accompanying notes to consolidated financial statements.

Note 1—Overview

Par Pacific Holdings, Inc. and its wholly owned subsidiaries ("Par" or the "Company") own, manage, and maintain interests in energy and infrastructure businesses. Our strategy is to identify, acquire, and operate energy and infrastructure companies with attractive competitive positions. Currently, we operate in three primary business segments:

1) **Refining** - Our refinery in Kapolei, Hawaii, produces ultra-low sulfur diesel ("ULSD"), gasoline, jet fuel, marine fuel, low sulfur fuel oil ("LSFO"), and other associated refined products primarily for consumption in Hawaii. Our refinery in Newcastle, Wyoming produces gasoline, ULSD, jet fuel, and other associated refined products that are primarily marketed in Wyoming and South Dakota.

2) **Retail** - Our retail outlets sell gasoline, diesel, and retail merchandise throughout the islands of Oahu, Maui, Hawaii, and Kauai. Our retail network includes Hele and "76" branded retail sites, company-operated convenience stores, 7-Eleven operated convenience stores, other sites operated by third parties, and unattended cardlock locations.

3) **Logistics** - We own and operate terminals, pipelines, a single-point mooring ("SPM") and trucking operations to distribute refined products throughout the islands of Oahu, Maui, Hawaii, Molokai, and Kauai. In addition, we own and operate a crude oil pipeline gathering system, a refined products pipeline, storage facilities, and loading racks in Wyoming. We also own and operate a jet fuel storage facility and pipeline that serve Ellsworth Air Force Base in South Dakota.

We also own a 42.3% equity investment in Laramie Energy, LLC (" Laramie Energy "), a joint venture entity operated by Laramie Energy II, LLC (" Laramie ") and focused on producing natural gas in Garfield, Mesa, and Rio Blanco Counties, Colorado.

Our Corporate and Other reportable segment includes administrative costs, our Texadian operations, and several small non-operated oil and gas interests that were owned by our predecessor.

Note 2—Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Par Pacific Holdings, Inc. and its subsidiaries. All intercompany balances and transactions have been eliminated in consolidation.

Certain amounts previously reported in our consolidated financial statements for prior periods have been reclassified to conform to the current presentation.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and the related disclosures. Actual amounts could differ from these estimates.

Cash and Cash Equivalents

Cash and cash equivalents consist of all highly liquid investments with original maturities of three months or less. The carrying value of cash equivalents approximates fair value because of the short-term nature of these investments.

Restricted Cash

Restricted cash consists of cash not readily available for general purpose cash needs. Restricted cash relates to bankruptcy matters.

Allowance for Doubtful Accounts

We establish provisions for losses on trade receivables if it becomes probable that we will not collect all or part of the outstanding balances. We review collectibility and establish or adjust our allowance as necessary using the specific identification method. As of December 31, 2017 and 2016 , we did not have a significant allowance for doubtful accounts.

Inventories

Commodity inventories are stated at the lower of cost or net realizable value using the first-in, first-out accounting method ("FIFO"). We value merchandise along with spare parts, materials, and supplies at average cost.

Beginning in June 2015, our refining segment acquires all of its crude oil utilized at the Hawaii refinery from J. Aron & Company ("J.Aron") under Supply and Offtake Agreements as described in Note 10—Inventory Financing Agreements . The crude oil remains in the legal title of J. Aron and is stored in our storage tanks governed by a storage agreement. Legal title to the crude oil passes to us at the tank outlet. After processing, J. Aron takes title to the refined products stored in our storage tanks until they are sold to our retail locations or to third parties. We record the inventory owned by J. Aron on our behalf as inventory with a corresponding obligation on our balance sheet because we maintain the risk of loss until the refined products are sold to third parties and are obligated to repurchase the inventory.

Prior to the Supply and Offtake Agreements with J. Aron, our refining and distribution segment acquired substantially all of its crude oil from Barclays Bank PLC ("Barclays") under Supply and Exchange Agreements as described in Note 10—Inventory Financing Agreements .

We enter into refined product and crude oil exchange agreements with other oil companies. Exchanges receivable or payable are stated at cost and are presented within Trade accounts receivable and Accounts payable on our consolidated balance sheets.

Investment in Laramie Energy, LLC

We account for our Investment in Laramie Energy, LLC using the equity method as we have the ability to exert significant influence, but do not control its operating and financial policies. Our proportionate share of net income (loss) of this entity is included in Equity earnings (losses) from Laramie Energy, LLC in the consolidated statements of operations. The investment is reviewed for impairment when events or changes in circumstances indicate that there has been an other than temporary decline in the value of the investment. Please read Note 3—Investment in Laramie Energy, LLC .

Property, Plant, and Equipment

We capitalize the cost of additions, major improvements, and modifications to property, plant, and equipment. The cost of repairs and normal maintenance of property, plant, and equipment is expensed as incurred. Major improvements and modifications of property, plant, and equipment are those expenditures that either extend the useful life, increase the capacity, or improve the operating efficiency of the asset or the safety of our operations. We compute depreciation of property, plant, and equipment using the straight-line method, based on the estimated useful life of each asset as follows:

Assets	Lives in Years
Refining	8 to 47
Logistics	3 to 30
Retail	14 to 18
Corporate	3 to 7
Software	3

We record property under capital leases at the lower of the present value of minimum lease payments using our incremental borrowing rate or the fair value of the leased property at the date of lease inception. We depreciate leasehold improvements and property acquired under capital leases over the shorter of the lease term or the economic life of the asset.

We review property, plant, and equipment and other long-lived assets whenever events or changes in business circumstances indicate the carrying value of the assets may not be recoverable. Impairment is indicated when the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. If this occurs, an impairment loss is recognized for the difference between the fair value and carrying value. Factors that indicate potential impairment include a significant decrease in the market value of the asset, operating or cash flow losses associated with the use of the asset, and a significant change in the asset's physical condition or use.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") in the period in which we have a legal obligation, whether by government action or contractual arrangement, to incur these costs and can make a reasonable estimate of the liability. Our AROs arise from our refining, logistics, and retail operations, as well as plugging and abandonment of wells within our natural gas and crude oil operations. AROs are calculated based on the present value of the estimated removal and other closure costs using our credit-adjusted risk-free rate. When the liability is initially recorded, we capitalize the cost by increasing the book value of the related long-lived tangible asset. The liability is accreted to its estimated settlement value with accretion expense recognized in Depreciation, depletion, and amortization ("DD&A") on our consolidated statements of operations and the related capitalized cost is depreciated over the asset's useful life. The difference between the settlement amount and the recorded liability is recorded as a gain or loss on asset disposals in our consolidated statements of operations. We estimate settlement dates by considering our past practice, industry practice, contractual terms, management's intent, and estimated economic lives.

We cannot currently estimate the fair value for certain AROs primarily because we cannot estimate settlement dates (or range of dates) associated with these assets. These AROs include hazardous materials disposal (such as petroleum manufacturing by-products, chemical catalysts, and sealed insulation material containing asbestos) and removal or dismantlement requirements associated with the closure of our refining facility, terminal facilities, or pipelines, including the demolition or removal of certain major processing units, buildings, tanks, pipelines, or other equipment.

Deferred Turnaround Costs

Refinery turnaround costs, which are incurred in connection with planned major maintenance activities at our refineries, are deferred and amortized on a straight-line basis over the period of time estimated until the next planned turnaround (generally three to five years). During 2016 , we recognized deferred turnaround costs of approximately $32.7 million . No deferred turnaround costs were recorded during 2017 . Deferred turnaround costs are presented within Other long-term assets on our consolidated balance sheets.

Goodwill and Other Intangible Assets

Goodwill represents the amount the purchase price exceeds the fair value of net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually on October 1. We assess the recoverability of the carrying value of goodwill during the fourth quarter of each year or whenever events or changes in circumstances indicate that the carrying amount of the goodwill of a reporting unit may not be fully recoverable. We first assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying value. If the qualitative assessment indicates that it is more likely than not that the carrying value of a reporting unit exceeds its estimated fair value, a quantitative test is required. Under the quantitative test, we compare the carrying value of the net assets of the reporting unit to the estimated fair value of the reporting unit. If the carrying value exceeds the estimated fair value of the reporting unit, an impairment loss is recorded.

Our intangible assets include relationships with customers, trade names, and trademarks. These intangible assets are amortized over their estimated useful lives on a straight-line basis. We evaluate the carrying value of our intangible assets when impairment indicators are present. When we believe impairment indicators may exist, projections of the undiscounted future cash flows associated with the use of and eventual disposition of the intangible assets are prepared. If the projections indicate that their carrying values are not recoverable, we reduce the carrying values to their estimated fair values.

Environmental Matters

We capitalize environmental expenditures that extend the life or increase the capacity of facilities as well as expenditures that prevent environmental contamination. We expense costs that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation. We record liabilities when environmental assessments and/or remedial efforts are probable and can be reasonably estimated. Cost estimates are based on the expected timing and extent of remedial actions required by governing agencies, experience gained from similar sites for which environmental assessments or remediation have been completed, and the amount of our anticipated liability considering the proportional liability and financial abilities of other responsible parties. Usually, the timing of these accruals coincides with the completion of a feasibility study or our commitment to a formal plan of action. Estimated liabilities are not discounted to present value and are presented within Other liabilities on our consolidated balance sheets. Environmental expenses are recorded in Operating expense (excluding depreciation) on our consolidated statements of operations.

Derivatives and Other Financial instruments

We are exposed to commodity price risk related to crude oil and refined products. We manage this exposure through the use of various derivative commodity instruments. These instruments include exchange traded futures and over-the-counter ("OTC") swaps, forwards, and options.

For our forward contracts that are derivatives, we have elected the normal purchase normal sale exclusion, as it is our policy to fulfill or accept the physical delivery of the product and we will not net settle. Therefore, we did not recognize the unrealized gains or losses related to these contracts in our consolidated financial statements. We apply the accrual method of accounting to our forwards contracts.

All derivative instruments not designated as normal purchases or sales are recorded in the balance sheet as either assets or liabilities measured at their fair values. Changes in the fair value of these derivative instruments are recognized currently in earnings. We have not designated any derivative instruments as cash flow or fair value hedges and, therefore, do not apply hedge accounting treatment.

In addition, we may have other financial instruments, such as warrants or embedded debt features, that may be classified as liabilities when either (a) the holders possess rights to net cash settlement, (b) physical or net equity settlement is not in our control, or (c) the instruments contain other provisions that cause us to conclude that they are not indexed to our equity. Our embedded derivatives include: our obligation to repurchase crude oil and refined products from J.Aron at the termination of the Supply and Offtake Agreements and the redemption option and the related make-whole premium on our 5.00% Convertible Senior Notes . These liabilities were initially recorded at fair value and subsequently adjusted to fair value at the end of each reporting period through earnings.

Please read Note 12—Derivatives and Note 13—Fair Value Measurements for information regarding our derivatives and other financial instruments.

Income Taxes

We use the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and net operating loss (“NOLs”) and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted income tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date. The realizability of deferred tax assets is evaluated quarterly based on a “more likely than not” standard and, to the extent this threshold is not met, a valuation allowance is recorded.

We recognize the impact of an uncertain tax position only if it is more likely than not of being sustained upon examination by the relevant taxing authority based on the technical merits of the position. As a general rule, our open years for Internal Revenue Service (“IRS”) examination purposes are 2014 , 2015 , and 2016 . However, since we have net operating loss carryforwards, the IRS has the ability to make adjustments to items that originate in a year otherwise barred by the statute of limitations in order to re-determine tax for an open year to which those items are carried. Therefore, in a year in which a net operating loss deduction is claimed, the IRS may examine the year in which the net operating loss was generated and adjust it accordingly for purposes of assessing additional tax in the year the net operating loss deductions was claimed. Any penalties or interest as a result of an examination will be recorded in the period assessed.

Stock-Based Compensation

We recognize the cost of share-based payments on a straight-line basis over the period the employee provides service, generally the vesting period, and include such costs in General and administrative expense (excluding depreciation) and Operating expense (excluding depreciation) in the consolidated statements of operations. The grant date fair value of restricted stock awards are equal to the market price of our common stock on the date of grant. The fair value of stock options are estimated using the Black-Scholes option-pricing model as of the date of grant.

Revenue Recognition

We recognize revenue when it is realized or realizable and earned. Revenue is realized or realizable and earned when persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the price to the buyer is fixed or determinable, and collectibility is reasonably assured. Revenue that does not meet these criteria is deferred until the criteria are met.

Certain transactions are recorded on a net basis and included in Cost of revenues (excluding depreciation) on our consolidated statements of operations. These transactions include nonmonetary crude oil and refined product exchange transactions, certain crude oil buy/sell arrangements, and sale and purchase transactions entered into with the same counterparty that are deemed to be in contemplation with one another.

Refining and Retail

We recognize revenues upon delivery of goods or services to a customer. For goods, this is the point at which title and risk of loss is transferred and when payment has either been received or collection is reasonably assured. Revenues for services are recorded when the services have been provided. We include transportation fees charged to customers in Revenues in our consolidated statements of operations, while the related transportation costs are included in Cost of revenues (excluding depreciation) .

Federal excise and state motor fuel taxes, which are collected from customers and remitted to governmental agencies within our refining and retail segments are excluded from both Revenues and Cost of revenues (excluding depreciation) in our consolidated statements of operations.

Logistics

We recognize transportation and storage fees as services are provided to a customer. Substantially all of our logistics revenues represent intercompany transactions that are eliminated in consolidation.

Cost Classifications

Cost of revenues (excluding depreciation) includes the hydrocarbon-related costs of inventory sold, transportation costs of delivering product to customers, crude oil consumed in the refining process, costs to satisfy our Renewable Identification Numbers (“RINs”) obligations, and certain hydrocarbon fees and taxes. Cost of revenues (excluding depreciation) also includes the unrealized gains (losses) on derivatives and inventory valuation adjustments. Certain direct operating expenses related to our logistics segment are also included in Cost of revenues (excluding depreciation) .

Operating expense (excluding depreciation) includes direct costs of labor, maintenance and services, energy and utility costs, property taxes, and environmental compliance costs as well as chemicals and catalysts and other direct operating expenses.

The following table summarizes depreciation expense excluded from each line item in our consolidated statements of operations (in thousands):

	Year Ended December 31,		
	2017	**2016**	**2015**
Cost of revenues	$ 6,029	$ 4,604	$ 3,017
Operating expense	22,861	16,340	11,428
General and administrative expense	2,929	2,108	855

Benefit Plans

We recognize an asset for the overfunded status or a liability for the underfunded status of our defined benefit pension plan. The funded status is recorded within Other long-term liabilities. Certain changes in the plan's funded status are recognized in Other comprehensive income (loss) in the period the change occurs.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are categorized with the highest priority given to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority given to unobservable inputs. The three levels of the fair value hierarchy are as follows:

Level 1 – Assets or liabilities for which the item is valued based on quoted prices (unadjusted) for identical assets or liabilities in active markets.
Level 2 – Assets or liabilities valued based on observable market data for similar instruments.

Level 3 – Assets or liabilities for which significant valuation assumptions are not readily observable in the market; instruments valued based on the best available data, some of which is internally-developed and considers risk premiums that a market participant would require.

The level in the fair value hierarchy within which the fair value measurement is categorized is based on the lowest level input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. Our policy is to recognize transfers in and/or out of fair value hierarchy levels as of the end of the reporting period for which the event or change in circumstances caused the transfer. We have consistently applied these valuation techniques for the periods presented. The fair value of the J. Aron repurchase obligation derivative is measured using estimates of the prices and differentials assuming settlement at the end of the reporting period.

Income (Loss) Per Share

Basic income (loss) per share ("EPS") is computed by dividing net income (loss) attributable to common stockholders by the sum of the weighted-average number of common shares outstanding and the weighted-average number of shares issuable under the warrants. The common stock warrants are included in the calculation of basic EPS because they are issuable for minimal consideration. Basic and Diluted ("EPS") are computed taking into account the effect of participating securities. Participating securities include restricted stock that has been issued but has not yet vested. Please read Note 17—Income (Loss) Per Share for further information.

Foreign Currency Transactions

We may, on occasion, enter into transactions denominated in currencies other than the U.S. dollar, which is our functional currency. Gains and losses resulting from changes in currency exchange rates between the functional currency and the currency in which a transaction is denominated are included in Other income (expense), net , in the accompanying consolidated statement of operations in the period in which the currency exchange rates change.

Accounting Principles Not Yet Adopted

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"). The FASB's objective was to provide a more robust framework to improve comparability of revenue recognition practices across entities by removing most industry and transaction specific guidance, align GAAP with International Financial Reporting Standards, and provide more useful information to financial statement users. This authoritative guidance changes the way entities recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date* ("ASU 2015-14"), which defers the effective date of ASU 2014-09 by one year. ASU 2014-09 is now effective for interim and annual periods beginning after December 15, 2017. Further amendments and technical corrections were made to ASU 2014-09 in 2016 and 2017. During 2016, we formally established a working group to assess the amended revenue recognition guidance in Topic 606, including its impact on our business processes, accounting systems, controls, and financial statement disclosures. As part of our evaluation, the working group reviewed existing revenue streams and identified the types of arrangements where differences may arise in revenue recognition upon adoption of the new standard. Our largest revenue stream consists of revenues generated from the sale of refined products, generally at market prices. These revenues are recognized upon delivery of goods to a customer. Our evaluation of this ASU is substantially complete and we currently do not expect the new standard to have a material impact on the amount or timing of revenues recognized for the sale of refined products.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* ("ASU 2016-02"). ASU 2016-02 requires lessees to recognize all leases, including operating leases, on the balance sheet as a lease asset or lease liability, unless the lease is a short-term lease. ASU 2016-02 also requires additional disclosures regarding leasing arrangements. In January 2018, the FASB issued ASU No. 2018-01 ("ASU 2018-01"), which clarifies the related transition and accounting for land easements. ASU 2016-02 and ASU No. 2018-01 are effective for interim periods and fiscal years beginning after December 15, 2018, and early application is permitted. We are in the process of determining the method of adoption and the impact this guidance will have on our financial condition, results of operations, and cash flow.

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). Additionally, in November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* ("ASU 2016-18"). The primary purpose of ASU 2016-15 is to reduce the diversity in practice relating to eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. ASU 2016-18 requires that an entity include restricted cash and restricted cash equivalents within its statement of cash flows and in the reconciliation to the statement of operations. The guidance in these ASUs is effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted. The new guidance must be applied using a retrospective transition method. We do not expect the adoption of ASU 2016-15 and ASU 2016-18 to have a material impact on our financial condition, results of operations, or cash flows.

In January 2017, the FASB issued ASU No. 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business* (“ASU 2017-01”). This ASU updates the definition of a business combination and provides a framework for determining whether a transaction involves an asset or a business. The guidance in this ASU is effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted. This ASU should be applied prospectively from the date of adoption. This ASU will change the policy under which we perform our assessments and accounting for future acquisition or disposal transactions.

In January 2017, the FASB issued ASU No. 2017-04, *Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (“ASU 2017-04”), which eliminates Step 2 from the current goodwill impairment test. Under ASU 2017-04, an entity is no longer required to determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. Under ASU 2017-04, an entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value. The guidance in this ASU is effective for fiscal years and interim periods beginning after December 15, 2019, with early adoption permitted. This ASU should be applied prospectively from the date of adoption. This ASU will change the policy under which we perform our annual goodwill impairment assessment by eliminating Step 2 of the test.

In March 2017, the FASB issued ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (“ASU 2017-07”). This ASU requires entities to (1) disaggregate the current-service-cost component from the other components of net benefit cost (the “other components”) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations if that subtotal is presented. In addition, the ASU requires entities to disclose the income statement lines that contain the other components if they are not presented on appropriately described separate lines. ASU 2017-07 is effective for interim and annual periods beginning after December 15, 2017. Early adoption is permitted as of the beginning of any annual period for which an entity’s financial statements (interim or annual) have not been issued or made available for issuance. ASU 2017-07 should be applied retrospectively for the presentation of cost components in the income statement and prospectively for the capitalization of the service cost component in assets. We do not expect the adoption of ASU 2017-07 to have a material impact on our financial condition, results of operations, or cash flows.

In May 2017, the FASB issued ASU 2017-09, *Compensation—Stock Compensation (Topic 718): Scope of Modification Accounting* (“ASU 2017-09”). The primary purpose of this ASU is to reduce the diversity in practice and cost and complexity in applying the guidance in Topic 718 related to the change to terms or conditions of a share-based payment award. The guidance in ASU 2017-09 is effective for fiscal years and interim periods beginning after December 15, 2017, with early adoption permitted. This ASU should be applied prospectively to an award modified on or after the adoption date. We do not expect the adoption of ASU 2017-09 to have a material impact on our financial condition, results of operations, or cash flows.

In February 2018, the FASB issued ASU No. 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* ("ASU 2018-02"). This ASU permits entities to elect to reclassify to retained earnings the stranded effects in Accumulated Other Comprehensive Income related to the changes in the statutory tax rate that were charged to income from continuing operations under the requirements of ASC 740. The guidance in ASU 2018-02 is effective for fiscal years and interim periods beginning after December 15, 2018, with early adoption permitted. Management is still evaluating the effects of the available adoption methods and has not yet determined which method will be elected.

Accounting Principles Adopted

On January 1, 2017, we adopted ASU No. 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* (“ASU 2016-09”). ASU 2016-09 simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements as well as classification in the statement of cash flows. Effective January 1, 2017, our accounting policy is to recognize forfeitures as they occur. The adoption of this ASU did not have a material impact on our financial condition, results of operations, or cash flows.

On January 1, 2017, we adopted ASU No. 2016-07, *Investments—Equity Method and Joint Ventures (Topic 323): Simplifying the Transition to the Equity Method of Accounting* (“ASU 2016-07”). ASU 2016-07 simplifies the equity method of accounting by eliminating the requirement to retrospectively apply the equity method to an investment that subsequently qualifies for such accounting as a result of an increase in the level of ownership interest or degree of influence. The adoption of this ASU did not have any impact on our financial condition, results of operations, or cash flows.

Note 3—Investment in Laramie Energy, LLC

We have a 42.3% ownership interest in Laramie Energy, a joint venture entity focused on developing and producing natural gas in Garfield, Mesa, and Rio Blanco Counties, Colorado. Laramie Energy has a $400 million revolving credit facility secured by a lien on its natural gas and crude oil properties and related assets with a borrowing base currently set at $230 million . As of December 31, 2017 and 2016 , the balance outstanding on the revolving credit facility was approximately $171.5 million and $117.5 million , respectively. We are guarantors of Laramie Energy ’s credit facility, with recourse limited to the pledge of our equity interest in our wholly owned subsidiary, Par Piceance Energy Equity, LLC. Under the terms of its credit facility, Laramie Energy is generally prohibited from making future cash distributions to its owners, including us.

On March 9, 2015 , we entered into an amendment to Laramie Energy's Limited Liability Company Agreement and made a cash capital contribution of $13.8 million to Laramie Energy . On May 29, 2015 , we made an additional cash capital contribution of $13.8 million . As a result of our contributions to Laramie Energy , our ownership interest increased from 33.34% to 34.0% .

On July 31, 2015 , an unaffiliated third party invested an aggregate of $19 million in Laramie Energy in the form of cash and property. As a result of this transaction, our ownership interest decreased from 34.0% to 32.4% .

At December 31, 2015, we conducted an impairment test related to our equity investment in Laramie Energy . As a result of the decline in commodity prices during 2015, we concluded that our equity investment in Laramie Energy was impaired and recognized an other-than-temporary impairment charge of $41.1 million on our consolidated statement of operations for the year ended December 31, 2015.

On March 1, 2016 , Laramie Energy acquired and assumed operatorship of certain properties in the Piceance Basin for $152.1 million , subject to customary purchase price adjustments (“Laramie Purchase”). In connection with the Laramie Purchase, we acquired additional membership interests of Laramie Energy for an aggregate cash purchase price of $55.0 million . As a result of this transaction, our ownership interest in Laramie Energy increased from 32.4% to 42.3% .

The change in our equity investment in Laramie Energy is as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ 108,823	$ 76,203	$ 104,657
Equity earnings (losses) from Laramie Energy	13,043	(28,198)	(15,713)
Accretion of basis difference	5,326	5,818	811
Impairment	—	—	(41,081)
Investments	—	55,000	27,529
Ending balance	$ 127,192	$ 108,823	$ 76,203

Summarized financial information for Laramie Energy is as follows (in thousands):

	December 31,	
	2017	2016
Current assets	$ 18,757	$ 12,199
Non-current assets	720,444	655,022
Current liabilities	42,149	58,067
Non-current liabilities	237,497	186,631

	Year Ended December 31,		
	2017	2016	2015
Natural gas and oil revenues	$ 157,879	$ 104,826	$ 42,870
Income (loss) from operations	6,019	(27,325)	(40,984)
Net income (loss)	30,837	(61,849)	(49,159)

Laramie Energy's net income for the year ended December 31, 2017 includes $50.3 million and $46.2 million of DD&A expense and unrealized gains on derivative instruments, respectively. Laramie Energy's net loss for the year ended December 31, 2016 includes $42.7 million and $34.5 million of DD&A expense and unrealized losses on derivative instruments, respectively. Laramie Energy's net loss for the year ended December 31, 2015 includes $24.6 million and $16.6 million of DD&A expense and unrealized gains on derivative instruments, respectively. Additionally, 2015 includes $12.3 million of impairments of unproved properties.

At December 31, 2017 and 2016 , our equity in the underlying net assets of Laramie Energy exceeded the carrying value of our investment by approximately $67.2 million and $69.9 million , respectively. This difference arose primarily due to lack of control and marketability discounts and an other-than-temporary impairment of our equity investment in Laramie Energy. We attributed this difference to natural gas and crude oil properties and are amortizing the difference over 15 years based on the estimated timing of production of proved reserves.

Note 4—Acquisitions

Wyoming Refining Company Acquisition

On June 14, 2016 , Par Wyoming, LLC, a wholly owned subsidiary of Par, entered into a unit purchase agreement (the “Purchase Agreement”) with Black Elk Refining, LLC to purchase all of the issued and outstanding units representing the membership interests in Hermes Consolidated, LLC (d/b/a Wyoming Refining Company) and, indirectly, Wyoming Refining Company ’s wholly owned subsidiary, Wyoming Pipeline Company, LLC (collectively, “ Wyoming Refining ”) (the “ WRC Acquisition ”). Wyoming Refining owns and operates a refinery and related logistics assets in Newcastle, Wyoming .

On July 14, 2016 , we completed the WRC Acquisition for cash consideration of $209.4 million , including a deposit of $5.0 million paid in June 2016, and assumed debt consisting of term loans of $58.0 million and revolving loans of $10.1 million . The consideration was paid with funds received from the issuance of our 2.50% convertible subordinated bridge notes (the “Bridge Notes”), cash on hand, which included the net proceeds from our June 2016 issuance and sale of an aggregate of $115 million principal amount of 5.00% convertible senior notes due 2021 (the “ 5.00% Convertible Senior Notes ”), and the issuance of a $65 million secured term loan by Par Wyoming Holdings, LLC (the “ Par Wyoming Holdings Credit Agreement ”). Please read Note 11—Debt for further information on the 5.00% Convertible Senior Notes , the Bridge Notes, and the Par Wyoming Holdings Credit Agreement .

We accounted for the WRC Acquisition as a business combination whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values on the date of the acquisition. Goodwill recognized in the transaction was attributable to opportunities expected to arise from combining our operations with Wyoming Refining and utilization of our net operating loss carryforwards, as well as other intangible assets that do not qualify for separate recognition. Goodwill recognized as a result of the WRC Acquisition is expected to be deductible for income tax reporting purposes.

During the three months ended June 30, 2017, the purchase price allocation was adjusted to record an increase of $2.0 million to our Wyoming refinery’s environmental liability as a result of additional information obtained by management regarding estimated remediation costs at certain locations. The purchase price allocation was also adjusted to record an increase to inventory of $0.5 million related to line fill inventory at our refined product pipelines. Goodwill increased $1.5 million as a result of these adjusting entries recorded during the three months ended June 30, 2017. As of June 30, 2017, we finalized the WRC Acquisition purchase price allocation.

A summary of the fair value of the assets acquired and liabilities assumed is as follows (in thousands):

Cash	$	183
Accounts receivable		16,880
Inventories		28,402
Prepaid and other assets		1,304
Property, plant, and equipment		254,367
Goodwill (1)		66,449
Accounts payable and other current liabilities		(57,861)
Wyoming Refining Senior Secured Revolver		(10,100)
Wyoming Refining Senior Secured Term Loan		(58,036)
Other non-current liabilities		(32,222)
Total	$	209,366

(1) We allocated $39.8 million and $26.6 million of goodwill to our refining and logistics segments, respectively.

We incurred $0.7 million of acquisition costs related to the WRC Acquisition for the year ended December 31, 2016 . These costs are included in acquisition and integration costs on our consolidated statement of operations.

The results of operations of Wyoming Refining were included in our results beginning July 14, 2016 . For the year ended December 31, 2016 , our results of operations included revenues of $174.6 million and net income of $0.7 million related to Wyoming Refining. The following unaudited pro forma financial information presents our consolidated revenues and net income (loss) as if the WRC Acquisition had been completed on January 1, 2015 (in thousands):

	Year Ended December 31,			
	2016		2015	
Revenues	$	2,026,237	$	2,369,513
Net income (loss)		(51,239)		(51,582)
Income (loss) per share				
Basic	$	(1.21)	$	(1.24)
Diluted	$	(1.21)	$	(1.24)

Mid Pac Acquisition

On April 1, 2015 , we completed the acquisition of Par Hawaii Inc. (“PHI,” formerly Koko’oha Investments, Inc.), a Hawaii corporation that owns 100% of the outstanding membership interests of Mid Pac Petroleum, LLC (“Mid Pac”). Net cash consideration was $74.4 million , including the working capital settlement of $1 million paid in September 2015. The cash consideration included advance deposits of $15 million , of which $10 million was paid in 2014, prior to closing. In connection with the acquisition, Mid Pac 's pre-existing debt was fully repaid on the closing date for $45.3 million . The acquisition and debt repayment were funded with cash on hand and $55 million of borrowings under a credit agreement with the Bank of Hawaii.

We accounted for the acquisition of Mid Pac as a business combination whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values on the date of acquisition. Goodwill recognized in the transaction was attributable to opportunities expected to arise from combining our operations with Mid Pac 's and utilization of our net operating loss carryforwards, as well as other intangible assets that do not qualify for separate recognition. In addition, we recorded certain other identifiable intangible assets including trade names and customer relationships. These intangible assets will be amortized over their estimated useful lives on a straight-line basis, which approximates their consumptive life. Please read Note 9—Goodwill and Intangible Assets for further discussion. None of the goodwill or intangible assets are expected to be deductible for income tax reporting purposes.

A summary of the fair value of the assets acquired and liabilities assumed is as follows (in thousands):

Cash	$	10,007
Accounts receivable		9,905
Inventories		5,375
Prepaid and other current assets		1,444
Property, plant and equipment		40,997
Land		34,800
Goodwill (1)		26,942
Intangible assets		33,647
Other non-current assets		1,228
Accounts payable and other current liabilities		(10,742)
Deferred tax liability		(16,759)
Other non-current liabilities		(7,235)
Total	$	129,609

(1) We allocated $13.5 million , $2.7 million , and $10.8 million of goodwill to our refining, retail, and logistics reporting units, respectively.

We incurred $0.8 million of acquisition costs related to the Mid Pac acquisition for the year ended December 31, 2015. These costs are included in acquisition and integration costs on our consolidated statement of operations.

The results of operations of Mid Pac were included in our refining , retail , and logistics segments results beginning April 1, 2015 . For the year ended December 31, 2015, our results of operations included Mid Pac 's revenues of $147.6 million and net income of $10.6 million , respectively. The following unaudited pro forma financial information presents our consolidated revenues and net income (loss) as if the Mid Pac acquisition had been completed on January 1, 2014 (in thousands):

	Year Ended December 31, 2015	
Revenues	$	2,093,587
Net loss		(54,941)

Note 5—Inventories

Inventories at December 31, 2017 and 2016 consist of the following (in thousands):

	Titled Inventory		Supply and Offtake Agreements (1)		Total	
December 31, 2017						
Crude oil and feedstocks	$	93,970	$	56,014	$	149,984
Refined products and blendstock		63,505		108,917		172,422
Warehouse stock and other		22,951		—		22,951
Total	$	180,426	$	164,931	$	345,357
December 31, 2016						
Crude oil and feedstocks	$	11,620	$	49,682	$	61,302
Refined products and blendstock		38,916		77,677		116,593
Warehouse stock and other		20,431		—		20,431
Total	$	70,967	$	127,359	$	198,326

(1) Please read Note 10—Inventory Financing Agreements for further information.

There was no reserve for the lower of cost or net realizable value of inventory as of December 31, 2017 . As of December 31, 2016 , the reserve for the lower of cost or net realizable value of inventory was $ 0.2 million .

Note 6—Prepaid and Other Current Assets

Prepaid and other current assets at December 31, 2017 and 2016 consist of the following (in thousands):

	December 31,	
	2017	2016
Advances to suppliers for crude oil purchases	$ —	$ 38,300
Collateral posted with broker for derivative instruments	215	2,714
Prepaid insurance	7,547	7,504
Derivative assets	4,296	161
Other	5,221	4,701
Total	$ 17,279	$ 53,380

Note 7—Property, Plant and Equipment

Major classes of property, plant and equipment consist of the following (in thousands):

	December 31,	
	2017	2016
Land	$ 79,330	$ 76,437
Buildings and equipment	433,977	412,999
Other	15,931	10,431
Total property, plant and equipment	529,238	499,867
Proved oil and gas properties	400	1,122
Less accumulated depreciation and depletion	(79,622)	(49,727)
Property, plant and equipment, net	$ 450,016	$ 451,262

Depreciation expense was approximately $31.8 million , $23.1 million , and $15.3 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively.

Note 8—Asset Retirement Obligations

The table below summarizes the changes in our recorded asset retirement obligations (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ 9,042	$ 8,909	$ 2,580
Obligations acquired	—	—	5,725
Accretion expense	369	362	604
Liabilities settled during period	(308)	(229)	—
Ending balance	$ 9,103	$ 9,042	$ 8,909

Note 9—Goodwill and Intangible Assets

During the years ended December 31, 2017 and 2016 , the change in the carrying amount of goodwill was as follows (in thousands):

Balance at January 1, 2016	$ 41,327
Acquisition of Wyoming Refining (1)	64,994
Mid Pac acquisition purchase price allocation adjustment (2)	(589)
Balance at December 31, 2016	105,732
Wyoming Refining acquisition purchase price allocation adjustment (1)	1,455
Balance at December 31, 2017	$ 107,187

(1) Please read Note 4—Acquisitions for further discussion.

(2) During 2016, the purchase price allocation was adjusted to record an increase to tax receivables and a decrease to goodwill of $0.6 million . The tax receivable was recorded in connection with a tax refund received by Mid Pac in the first quarter of 2016.

Intangible assets consist of the following (in thousands):

	December 31,	
	2017	2016
Intangible assets:		
Railcar leases	$ 3,249	$ 3,249
Trade names and trademarks	6,267	6,267
Customer relationships	32,064	32,064
Total intangible assets	41,580	41,580
Accumulated amortization:		
Railcar leases	(3,249)	(2,599)
Trade name and trademarks	(4,951)	(4,864)
Customer relationships	(6,776)	(4,205)
Total accumulated amortization	(14,976)	(11,668)
Net:		
Railcar leases	—	650
Trade name and trademarks	1,316	1,403
Customer relationships	25,288	27,859
Total intangible assets, net	$ 26,604	$ 29,912

At September 30, 2015, we conducted an impairment test related to goodwill and intangible assets in our Texadian reporting unit. As of result of canceling the charter on the barges used to transport crude from Canada to the U.S. Gulf Coast in the Texadian business and negative cash flows, we concluded that goodwill and the supplier relationships intangible asset were fully impaired at September 30, 2015. We recognized impairment charges for goodwill and intangible assets of $7.0 million and $2.6 million in our consolidated statement of operations for the year ended December 31, 2015, respectively.

Amortization expense was approximately $3.3 million , $4.5 million , and $4.4 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively. Our intangible assets related to customer relationships and trade names have an average useful life of 13.6 years . Expected amortization expense for each of the next five years and thereafter is as follows (in thousands):

Year Ended	Amount
2018	$ 2,658
2019	2,658
2020	2,658
2021	2,658
2022	2,658
Thereafter	13,314
	$ 26,604

Note 10—Inventory Financing Agreements

Supply and Offtake Agreements

On June 1, 2015, we entered into several agreements with J. Aron to support the operations of our Hawaii refinery (the “Supply and Offtake Agreements”). On May 8, 2017 , we and J. Aron amended the Supply and Offtake Agreements and extended the term through May 31, 2021 with a one -year extension option upon mutual agreement of the parties. As part of this amendment, J. Aron may enter into agreements with third parties whereby J. Aron will remit payments to these third parties for refinery procurement contracts for which we will become immediately obligated to reimburse J. Aron. As of December 31, 2017 , we had no obligations due to J. Aron under this letter of credit agreement. On December 21, 2017, in connection with the issuance of the 7.75% Senior Secured Notes , we amended and restated the Supply and Offtake Agreements to update the terms of the collateral as noted below.

During the term of the Supply and Offtake Agreements, we and J. Aron will identify mutually acceptable contracts for the purchase of crude oil from third parties. Per the Supply and Offtake Agreements, J. Aron will provide up to 94 thousand barrels per day of crude oil to our Hawaii refinery. Additionally, we agreed to sell and J. Aron agreed to buy, at market prices, refined products produced at our Hawaii refinery. We will then repurchase the refined products from J. Aron prior to selling the refined products to our retail operations or to third parties. The agreements also provide for the lease of crude oil and certain refined product storage facilities to J. Aron. Following expiration or termination of the Supply and Offtake Agreements, we are obligated to purchase the crude oil and refined product inventories then owned by J. Aron and located at the leased storage facilities at then-current market prices. In connection with the December 21, 2017 amendment and restatement of the Supply and Offtake Agreements, certain collateral (including the mortgage liens on the real property and improvements comprising the Hawaii refinery and on all equipment used to operate the Hawaii refinery, the equity interests in Par Hawaii Refining, LLC ("PHR") held by Par Petroleum, LLC, and certain other items of personal property) was released, and Par Petroleum, LLC issued an unsecured guaranty in favor of J. Aron pursuant to which Par Petroleum, LLC guarantees the payment and performance of certain liabilities of PHR under the Supply and Offtake Agreements.

Though title to the crude oil and certain refined product inventories resides with J. Aron, the Supply and Offtake Agreements are accounted for similar to a product financing arrangement; therefore, the crude oil and refined products inventories will continue to be included on our consolidated balance sheets until processed and sold to a third party. Each reporting period, we record a liability in an amount equal to the amount we expect to pay to repurchase the inventory held by J. Aron based on current market prices.

For the years ended December 31, 2017 , 2016 , and 2015 , we incurred approximately $13.7 million , $7.8 million , and $6.9 million in handling fees related to the Supply and Offtake Agreements, respectively, which are included in Cost of revenues (excluding depreciation) on our consolidated statements of operations. For the years ended December 31, 2017 , 2016 , and 2015 , Interest expense and financing costs, net on our consolidated statements of operations includes approximately $2.3 million , $3.2 million , and $1.5 million of expenses related to the Supply and Offtake Agreements, respectively.

The Supply and Offtake Agreements also include a deferred payment arrangement (“Deferred Payment Arrangement”) whereby we can defer payments owed under the agreements up to the lesser of $125 million or 85% of the eligible accounts receivable and inventory. Upon execution of the Supply and Offtake Agreements, we paid J. Aron a deferral arrangement fee of $1.3 million . The deferred amounts under the Deferred Payment Arrangement will bear interest at a rate equal to three-month

LIBOR plus 3.75% per annum. We also agreed to pay a deferred payment availability fee equal to 0.75% of the unused capacity under the Deferred Payment Arrangement. Amounts outstanding under the Deferred Payment Arrangement are included in Obligations under inventory financing agreements on our consolidated balance sheets. Changes in the amount outstanding under the Deferred Payment Arrangement are included within Cash flows from financing activities on the consolidated statements of cash flows. As of December 31, 2017 , the capacity of the Deferred Payment Arrangement was $83.1 million and we had $41.1 million outstanding.

Under the Supply and Offtake Agreements, we pay or receive certain fees from J. Aron based on changes in market prices over time. In September 2015, we entered into an agreement to fix this market fee for the period from October 1, 2015 through November 30, 2016 whereby J. Aron agreed to pay us a total of $18 million to be settled in fourteen equal monthly payments. In February 2016, we fixed the market fee for the remainder of the term of the Supply and Offtake Agreements for an additional $14.6 million to be settled in eighteen equal monthly payments. In 2017, we fixed the market fee for the period from June 1, 2018 through May 2021 for an additional aggregate $2.2 million . The receivable from J. Aron was recorded as a reduction to our Obligations under inventory financing agreements pursuant to our Master Netting Agreement. As of December 31, 2017 , the receivable was $7.1 million .

The agreements also provide us with the ability to economically hedge price risk on our inventories and crude oil purchases. Please read Note 12—Derivatives for further information.

Supply and Exchange Agreements

On September 25, 2013, we entered into several agreements with Barclays for the purpose of managing our working capital and the crude oil and refined product inventory at the Hawaii refinery (the "Supply and Exchange Agreements"). Effective July 31, 2014, we supplemented the Supply and Exchange Agreements by entering into the Refined Product Supply Master Confirmation, pursuant to which Barclays provided refined product supply and intermediation arrangements to us.

For the year ended December 31, 2015, we incurred approximately $6.9 million in handling fees related to the Supply and Exchange Agreements, which are included in Cost of revenues (excluding depreciation) on our consolidated statements of operations. For the year ended December 31, 2015, Interest expense and financing costs, net on our consolidated statements of operations includes approximately $2.3 million of expenses related to the Supply and Exchange Agreements.

Upon execution of the Supply and Offtake Agreements, we terminated the Supply and Exchange Agreements with Barclays, subject to certain obligations to reimburse Barclays for third-party claims. We recognized a loss of $17.4 million on the termination of the agreement which consisted of a loss of $13.3 million for the cash settlement value of the liability which had previously been measured assuming settlement with inventory on hand and a loss of $5.6 million for the acceleration of deferred financing costs. These losses were partially offset by a $1.5 million exit fee received from Barclays. The net loss of $17.4 million related to the termination of the Supply and Exchange Agreements is included in Loss on termination of financing agreements on our consolidated statements of operations for the year ended December 31, 2015. The cash paid to settle the obligation is included in Payments for termination of supply and exchange agreements in our consolidated statements of cash flows for the year ended December 31, 2015.

Note 11—Debt

The following table summarizes our outstanding debt as of December 31, 2017 and 2016 (in thousands):

	December 31,	
	2017	2016
Hawaii Retail Credit Facilities	$ —	$ 95,319
5.00% Convertible Senior Notes due 2021	115,000	115,000
7.75% Senior Secured Notes due 2025	300,000	—
Term Loan	—	60,361
Par Wyoming Holdings Term Loan	—	67,325
Wyoming Refining Senior Secured Term Loan	—	55,715
Wyoming Refining Senior Secured Revolver	—	6,700
Principal amount of long-term debt	415,000	400,420
Less: unamortized discount and deferred financing costs	(30,188)	(30,024)
Total debt, net of unamortized discount and deferred financing costs	384,812	370,396
Less: current maturities	—	(20,286)
Long-term debt, net of current maturities	$ 384,812	$ 350,110

Annual maturities of our long-term debt for the next five years and thereafter are as follows (in thousands):

Year Ended	Amount Due
2018	$ —
2019	—
2020	—
2021	115,000
2022	—
Thereafter	300,000
Total	$ 415,000

Our debt is subject to various affirmative and negative covenants. As of December 31, 2017 , we were in compliance with all debt covenants. Under the ABL Credit Facility and the indenture governing the 7.75% Senior Secured Notes , our subsidiaries are restricted from paying dividends or making other equity distributions, subject to certain exceptions.

7.75% Senior Secured Notes Due 2025

On December 21, 2017 , Par Petroleum, LLC and Par Petroleum Finance Corp. (collectively, the "Issuers"), both our wholly-owned subsidiaries, completed the issuance and sale of $300 million in aggregate principal amount of 7.75% Senior Secured Notes in a private placement under Rule 144A and Regulation S of the Securities Act of 1933, as amended. The net proceeds of $289.2 million (net of financing costs and original issue discount of 1%) from the sale were used to repay the Hawaii Retail Credit Facilities , the Wyoming Refining Credit Facilities , the Par Wyoming Holdings Credit Agreement , and the J. Aron Forward Sale , and for general corporate purposes.

The 7.75% Senior Secured Notes bear interest at a rate of 7.750% per year beginning December 21, 2017 (payable semi-annually in arrears on June 15 and December 15 of each year, beginning on June 15, 2018) and will mature on December 15, 2025 .

The indenture governing the 7.75% Senior Secured Notes contains restrictive covenants limiting the ability of Par Petroleum, LLC and its Restricted Subsidiaries (as defined in the indenture) to, among other things, incur additional indebtedness, issue certain preferred shares, create liens on certain assets to secure debt, sell or otherwise dispose of all or substantially all assets, or pay dividends.

The 7.75% Senior Secured Notes are secured by first priority liens (subject to the relative priority of permitted liens) on substantially all of the property and assets of the Issuers and the subsidiary guarantors, including but not limited to, material real property now owned or hereafter acquired by the Issuers or subsidiary guarantors and their equipment, intellectual property, and equity interests, but excluding certain property which is collateral under the ABL Credit Facility and collateral under the Supply and Offtake Agreements. The 7.75% Senior Secured Notes are fully and unconditionally guaranteed on a senior secured basis, jointly and severally, by each of Par Petroleum, LLC ’s existing wholly-owned subsidiaries (other than Par Petroleum Finance Corp.), and are guaranteed on a senior unsecured basis only as to the payment of principal and interest by Par Pacific Holdings, Inc. In the future, the 7.75% Senior Secured Notes will be guaranteed on a senior secured basis by additional subsidiaries of Par Petroleum, LLC that guarantee material indebtedness of the Issuers or otherwise become obligated with respect to material indebtedness under a credit facility, subject to certain exceptions.

ABL Credit Facility

On December 21, 2017 , in connection with the issuance of the 7.75% Senior Secured Notes , Par Petroleum, LLC , PHI, Mid Pac, HIE Retail, LLC, and WRC (collectively, the “ ABL Borrowers ”), entered into a Loan and Security Agreement dated as of December 21, 2017 (the “ ABL Credit Facility ”) with certain lenders and Bank of America, N.A., as administrative agent and collateral agent. The ABL Credit Facility provides for a revolving credit facility in the maximum principal amount at any time outstanding of $75 million , subject to a borrowing base, which provides for revolving loans and for the issuance of letters of credit (the “ ABL Revolver ”). The ABL Revolver was undrawn and had a borrowing base of approximately $48.7 million at December 31, 2017 .

The revolving loans under the ABL Revolver bear interest at a fluctuating rate per annum equal to (i) during the periods such revolving loan is a base rate loan, the base rate plus the applicable margin in effect from time to time, and (ii) during the periods such revolving loan is a LIBOR Loan, at LIBOR for the applicable interest period plus the applicable margin in effect from time to time. The base rate is equal to (i) daily LIBOR ("LIBOR Daily Floating Rate") or (ii) if the LIBOR Daily Floating Rate is unavailable for any reason, a rate as calculated per the agreement (the "Prime Rate") for such day. The maturity date of the ABL Revolver is December 21, 2022 , on which date all revolving loans will be due and payable in full.

The applicable margins for the ABL Credit Facility and advances under the ABL Revolver are as specified below:

Level	Arithmetic Mean of Daily Availability (as a percentage of the borrowing base)	Applicable Margin for LIBOR Loans and Base Rate Loans Subject to LIBOR Daily Floating Rate	Applicable Margin for Base Rate Loans Subject to the Prime Rate
1	>50%	1.75%	0.75%
2	>30% but ≤ 50%	2.00%	1.00%
3	≤ 30%	2.25%	1.25%

The obligations of the ABL Borrowers are guaranteed by Par and Par Petroleum, LLC 's existing and future direct or indirect domestic subsidiaries that are not borrowers under the ABL Credit Facility . The loans and letters of credit issued under the ABL Credit Facility are secured by a first-priority security interest in and lien on certain assets of the borrowers and the guarantors, including cash and cash equivalents and inventory, and excluding the assets of PHR.

J. Aron Forward Sale

As part of the May 8, 2017 amendment to the Supply and Offtake Agreements , we also entered into a $30 million forward sale of jet fuel to be delivered to J. Aron over the amended term (“ J. Aron Forward Sale ”). The proceeds from the J. Aron Forward Sale were used to pay a portion of the outstanding balance on the Term Loan (as defined below). The cost of the J. Aron Forward Sale was based upon an annual interest rate of 7% .

Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the J. Aron Forward Sale and recognized $0.3 million of costs associated with the termination of the agreement, which is included within Loss on termination of financing agreements on our consolidated statement of operations for the year ended December 31, 2017.

Par Wyoming Holdings Credit Agreement

On July 14, 2016 , in connection with the WRC Acquisition , Par Wyoming Holdings, LLC, our indirect wholly owned subsidiary, entered into the Par Wyoming Holdings Credit Agreement with certain lenders and Chambers Energy Management, LP, as agent, which provided for a single advance secured term loan to our subsidiary in the amount of $65.0 million (the “ Par Wyoming Holdings Term Loan ”) at the closing of the WRC Acquisition . The proceeds of the Par Wyoming Holdings Term Loan were used to pay a portion of the consideration for the WRC Acquisition , to pay certain fees and closing costs, and for general corporate purposes. The Par Wyoming Holdings Term Loan was originally scheduled to mature on July 14, 2021 .

The Par Wyoming Holdings Term Loan bore interest at a rate equal to three-month LIBOR plus an applicable interest margin. With respect to cash interest, the applicable interest margin was at a rate per annum equal to 9.5% . With respect to paid-in-kind (“PIK”) interest, the applicable interest margin was at a rate per annum equal to 13% . Interest was payable in arrears on (a) the last day of each fiscal quarter, (b) the maturity date, and (c) the date of any repayment or prepayment of the Par Wyoming Holdings Term Loan .

Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Par Wyoming Holdings Credit Agreement and recognized $5.2 million of costs associated with the termination of the agreement, which is included within Loss on termination of financing agreements on our consolidated statement of operations for the year ended December 31, 2017.

Wyoming Refining Credit Facilities

Wyoming Refining Company and its wholly owned subsidiary, Wyoming Pipeline Company LLC, were borrowers (the “ Wyoming Refining Credit Facility Borrowers ”) under a Third Amended and Restated Loan Agreement dated as of April 30, 2015 (as amended, the “ Wyoming Refining Credit Facilities ”), with Bank of America, N.A., as the lender. The Wyoming Refining Credit Facilities remained in place following the consummation of the WRC Acquisition .

On July 14, 2016 , and in connection with the consummation of the WRC Acquisition , the Wyoming Refining Credit Facilities were amended pursuant to a Third Amendment to Third Amended and Restated Loan Agreement (the “Third Loan Amendment”) and a Fourth Amendment to Third Amended and Restated Loan Agreement (the “Fourth Loan Amendment”). Pursuant to the Third Loan Amendment, which was entered into immediately prior to the consummation of the WRC Acquisition , Black Elk Refining, LLC was released from all of its obligations under the Wyoming Refining Credit Facilities and Par Wyoming, LLC joined and became a party to the Wyoming Refining Credit Facilities and the applicable security agreement and guaranteed all obligations of the borrowers under the Wyoming Refining Credit Facilities . The Fourth Loan Amendment was entered into immediately following the consummation of the WRC Acquisition and amended certain covenants in the Wyoming Refining Credit Facilities applicable to Par Wyoming, LLC and the Wyoming Refining Credit Facility Borrowers . On August 7, 2017 , we entered into an amendment to the Wyoming Refining Credit Facilities to extend the maturity date from April 30, 2018 until June 30, 2019.

The Wyoming Refining Credit Facilities originally provided for (a) a revolving credit facility in the maximum principal amount at any time outstanding of $30 million (“ Wyoming Refining Senior Secured Revolver ”), subject to a borrowing base, which provided for revolving loans and for the issuance of letters of credit and (b) certain term loans that are fully advanced (“ Wyoming Refining Senior Secured Term Loan ”). The Wyoming Refining Senior Secured Term Loan bore interest at a rate equal to monthly LIBOR plus 3.0% . The Wyoming Refining Senior Secured Term Loan required quarterly principal payments of $2.3 million .

Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Wyoming Refining Credit Facilities and recognized $0.1 million of costs associated with the termination of the agreement, which is included within Loss on termination of financing agreements on our consolidated statement of operations for the year ended December 31, 2017.

5.00% Convertible Senior Notes Due 2021

In June 2016, we completed the issuance and sale of $115 million in aggregate principal amount of the 5.00% Convertible Senior Notes in a private placement under Rule 144A (the “Notes Offering”). The Notes Offering included the exercise in full of an option to purchase an additional $15 million in aggregate principal amount of the 5.00% Convertible Senior Notes granted to the initial purchasers. The net proceeds of $111.6 million (net of original issue discount of 3%) from the sale of the 5.00% Convertible Senior Notes were used to finance a portion of the WRC Acquisition , to repay $5 million in principal amount of the Term Loan (as defined below), and for general corporate purposes.

The 5.00% Convertible Senior Notes bear interest at a rate of 5.00% per year beginning June 21, 2016 (payable semi-annually in arrears on June 15 and December 15 of each year, beginning on December 15, 2016) and will mature on June 15, 2021 . The initial conversion rate for the notes is 55.5556 shares of common stock per $1,000 principal amount of the 5.00% Convertible Senior Notes (or a total amount of 6,388,894 shares), which is equivalent to an initial conversion price of approximately $18.00 per share of common stock, subject to adjustment upon the occurrence of certain events. Conversions of the 5.00% Convertible Senior Notes will be settled in cash, shares of common stock, or a combination thereof at our election. The holders of the 5.00% Convertible Senior Notes may exercise their conversion rights at any time prior to the close of business on the business day immediately preceding the maturity date under certain circumstances.

The 5.00% Convertible Senior Notes are not redeemable by us prior to June 20, 2019 . On or after June 20, 2019 , we may redeem all or any portion of the 5.00% Convertible Senior Notes if the last reported sales price of our common stock is at least 140% of the conversion price then in effect (i) on the trading day immediately preceding the date on which we provide notice of redemption and (ii) for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period ending on, and including, the trading day immediately preceding the date on which we provide notice of redemption at a redemption price equal to 100% of the principal amount of the 5.00% Convertible Senior Notes to be redeemed, plus accrued and unpaid interest and a make-whole premium, which is equal to the present value of the remaining scheduled payments of interest on the 5.00% Convertible Senior Notes to be redeemed from the relevant redemption date to the maturity date of June 15, 2021 . We have determined that the redemption option and the related make-whole premium represent an embedded derivative that is not clearly and closely related to the 5.00% Convertible Senior Notes . Please read Note 12—Derivatives for further information on embedded derivatives.

We separately account for the liability and equity components of the 5.00% Convertible Senior Notes . The fair value of the liability component was calculated using a discount rate of an identical debt instrument without a conversion feature. Based on this borrowing rate, the fair value of the liability component of the 5.00% Convertible Senior Notes on the issuance date was $89.3 million . The carrying amount of the equity component was determined to be $22.2 million by deducting the fair value of the liability component from the $111.6 million net proceeds of the 5.00% Convertible Senior Notes . The deferred financing costs of $0.6 million related to 5.00% Convertible Senior Notes were allocated on a proportionate basis between Long-term debt and Additional paid-in capital on the consolidated balance sheet. As of December 31, 2017 , the if-converted value was $8.2 million in excess of the outstanding principal amount of the 5.00% Convertible Senior Notes .

As of December 31, 2017 , the outstanding principal amount of the 5.00% Convertible Senior Notes was $115.0 million , the unamortized discount and deferred financing cost was $19.5 million and the carrying amount of the liability component was $95.5 million . The unamortized discount and deferred financing costs will be amortized to Interest expense and financing costs, net over the term of the 5.00% Convertible Senior Notes .

Hawaii Retail Credit Facilities

On December 17, 2015 , we entered into the Hawaii Retail Credit Facilities in the form of a revolving credit facility up to $5 million (" Hawaii Retail Revolving Credit Facilities ") that provided for revolving loans and for the issuance of letters of credit and term loans (" Hawaii Retail Term Loans ") in the aggregate principal amount of $110 million . The proceeds of the Hawaii Retail Term Loans were used to repay in full existing indebtedness under the previous credit facilities, to pay transaction fees and expenses, to repay a portion of existing indebtedness under the Term Loan (as defined below), and to facilitate a cash distribution to Par.

The Hawaii Retail Term Loans originally matured on December 17, 2022 and required principal payments of $2.75 million on the last business day of each fiscal quarter. The Hawaii Retail Revolving Credit Facilities originally matured on December 17, 2020 .

The Hawaii Retail Term Loans and advances under the Hawaii Retail Revolving Credit Facilities bore interest at a fluctuating rate (i) during the periods such revolving loan or term loan, as applicable, equal to a Base Rate Loan, the Base Rate plus an applicable margin ranging from 1.50% to 2.25% , and (ii) during the periods such revolving loan or term loan, as applicable, equal to a Eurodollar Loan, the relevant Adjusted Eurodollar Rate for such Eurodollar Loan for the applicable interest period plus an applicable margin ranging from 2.50% to 3.25% . The effective interest rate for 2017 on the outstanding loan was 4.0% .

Upon issuance of the 7.75% Senior Secured Notes on December 21, 2017 , we repaid in full and terminated the Hawaii Retail Credit Facilities and recognized $1.2 million of costs associated with the termination of the agreement, which is included within Loss on termination of financing agreements on our consolidated statement of operations for the year ended December 31, 2017.

Bridge Notes

On July 14, 2016 , we issued approximately $52.6 million in aggregate principal amount of bridge notes in a private offering pursuant to the terms of a note purchase agreement (the "Bridge Notes") entered into among the purchasers of the Bridge Notes and us. On September 22, 2016 , we completed a registered pro-rata subscription rights offering of approximately 4 million shares of our common stock (the "Rights Offering"). The Rights Offering resulted in gross proceeds, before expenses, of approximately $49.9 million . We used the net proceeds from the Rights Offering to repay all accrued and unpaid interest and a portion of the outstanding principal amount on the Bridge Notes. The remaining $3.1 million aggregate principal amount and $0.3 million unpaid interest of the Bridge Notes was mandatorily converted into 272,733 shares of our common stock based on a conversion price of $12.25 per share. In connection with our repayment of the Bridge Notes, we expensed $3.0 million of financing costs, which are included within Interest expense and financing costs, net on our consolidated statements of operations for the year ended December 31, 2016 .

Term Loan

On July 11, 2014 , we and certain subsidiaries entered into a Delayed Draw Term Loan and Bridge Loan Credit Agreement ("Credit Agreement"), amending and restating a previous borrowing arrangement with the lenders, to provide us with a term loan of up to $50.0 million ("Term Loan") and a bridge loan of up to $75.0 million ("Bridge Loan"). The lenders under the Credit Agreement include ZCOF Par Petroleum Holdings, LLC and Highbridge International, LLC, who are also our significant stockholders. Proceeds from the Term Loan were used to fund a deposit per the Mid Pac merger agreement, to pay transaction costs, and for working capital and general corporate purposes.

On June 15, 2016 , the Credit Agreement was amended to permit (i) the issuance of the 5.00% Convertible Senior Notes , (ii) the issuance of our Bridge Notes, and (iii) the WRC Acquisition . We paid a consent fee of $2.5 million in connection with this amendment, $1.3 million of which was paid to an affiliate of Whitebox Advisors, LLC ("Whitebox"), one of our largest stockholders. On June 21, 2016 , we repaid $5 million of the Term Loan pursuant to the terms of the amendment, $3.3 million of which was allocated to an affiliate of Whitebox. Please read Note 20—Related Party Transactions for additional information.

The Term Loan originally matured on July 11, 2018 and bore interest at either 10% per annum if paid in cash or 12% per annum if paid in kind, at our election, and had an original issue discount of 5% .

On June 30, 2017, we fully repaid the Term Loan and terminated the Credit Agreement. A portion of the proceeds from the J. Aron Forward Sale and cash flows from operations were used to repay the full amount outstanding. We recorded a loss on termination of approximately $1.8 million related to unamortized deferred financing costs associated with the Term Loan in the year ended December 31, 2017 .

Cross Default Provisions

Included within each of our debt instruments are customary cross default provisions that require the repayment of amounts outstanding on demand should an event of default occur and not be cured within the permitted grace period, if any. As of December 31, 2017 , we are in compliance with all of our debt instruments.

Guarantors

In connection with our shelf registration statement on Form S-3, which was filed with the SEC on September 2, 2016 and declared effective on September 16, 2016 ("Registration Statement"), we may sell non-convertible debt securities and other securities in one or more offerings with an aggregate initial offering price of up to $750.0 million . Any non-convertible debt securities issued under the Registration Statement may be fully and unconditionally guaranteed (except for customary release provisions), on a joint and several basis, by some or all of our subsidiaries, other than subsidiaries that are "minor" within the meaning of Rule 3-10 of Regulation S-X (the "Guarantor Subsidiaries"). We have no "independent assets or operations" within the meaning of Rule 3-10 of Regulation S-X and certain of the Guarantor Subsidiaries are subject to restrictions on their ability to distribute funds to us, whether by cash dividends, loans, or advances.

Note 12—Derivatives

Commodity Derivatives

We utilize crude oil commodity derivative contracts to manage our price exposure in our inventory positions, future purchases of crude oil, future sales of refined products, and crude oil consumption in our refining process. The derivative contracts that we execute to manage our price risk include exchange traded futures, options, and OTC swaps. Our futures, options, and OTC swaps are marked-to-market and changes in the fair value of these contracts are recognized within Cost of revenues (excluding depreciation) on our consolidated statements of operations.

We are obligated to repurchase the crude oil and refined products from J. Aron at the termination of the Supply and Offtake Agreements. We have determined that this obligation contains an embedded derivative, similar to forward purchase contracts of crude oil and refined products. As such, we have accounted for this embedded derivative at fair value with changes in the fair value recorded in Cost of revenues (excluding depreciation) on our consolidated statements of operations. We are also required under the Supply and Offtake Agreements to hedge the time spread between the period of crude oil cargo pricing and the month of delivery. We utilize OTC swaps to accomplish this.

We have entered into forward purchase contracts for crude oil and forward sales contracts of refined products. We elect the normal purchases normal sales ("NPNS") exception for all forward contracts that meet the definition of a derivative and are not expected to net settle. Any gains and losses with respect to these forward contracts designated as NPNS are not reflected in earnings until the delivery occurs.

We elect to offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting agreement. Our consolidated balance sheets present derivative assets and liabilities on a net basis. Please read Note 13—Fair Value Measurements for the gross fair value and net carrying value of our derivative instruments. Our cash margin that is required as collateral deposits cannot be offset against the fair value of open contracts except in the event of default.

At December 31, 2017 , our open commodity derivative contracts represented:

- futures sales contracts of 200 thousand barrels that economically hedge our crude oil and refined product inventory;
- OTC swap purchases of 321 thousand barrels that economically hedge our crude oil and refined products month-end target inventory under our Supply and Offtake Agreements;
- net OTC swaps and futures sales contracts of 140 thousand barrels that economically hedge our sales of refined products; and
- option collars of 60 thousand barrels per month and OTC swaps of 15 thousand barrels per month through December 2018 that economically hedge our internally consumed fuel.

Interest Rate Derivatives

We are exposed to interest rate volatility in the Supply and Offtake Agreements. We utilize interest rate swaps to manage our interest rate risk. As of December 31, 2017 , we had locked in an average fixed rate of 1.1% in exchange for a floating interest rate indexed to the three-month LIBOR on an aggregate notional amount of $200.0 million . The interest rate swaps mature in February 2019 and March 2021.

In June 2016, we completed the issuance and sale of an aggregate of $115.0 million principal amount of the 5.00% Convertible Senior Notes . Please read Note 11—Debt for further discussion. Upon redemption of our 5.00% Convertible Senior Notes on or after June 20, 2019 at our election, we are obligated to pay a make-whole premium equal to the present value of the remaining scheduled payments of interest on the 5.00% Convertible Senior Notes to be redeemed from the relevant redemption date to the maturity date of June 15, 2021 . We have determined that the redemption option and the related make-whole premium represent an embedded derivative that is not clearly and closely related to the 5.00% Convertible Senior Notes . As such, we have accounted for this embedded derivative at fair value with changes in the fair value recorded in Interest expense and financing costs, net on our consolidated statements of operations. As of December 31, 2017 , this embedded derivative was deemed to have a *de minimis* fair value.

The following table provides information on the fair value amounts (in thousands) of these derivatives as of December 31, 2017 and 2016 and their placement within our consolidated balance sheets.

	Balance Sheet Location	December 31, 2017	December 31, 2016
		Asset (Liability)	
Commodity derivatives (1)	Prepaid and other current assets	$ 2,814	$ —
Commodity derivatives (1)	Other long-term assets	—	2,748
Commodity derivatives	Other accrued liabilities	(39)	(595)
J. Aron repurchase obligation derivative	Obligations under inventory financing agreements	(19,564)	(20,000)
Interest rate derivatives	Prepaid and other current assets	1,482	161
Interest rate derivatives	Other long-term assets	2,328	3,377
Interest rate derivatives	Other accrued liabilities	—	(94)

(1) Does not include cash collateral of $0.2 million and $2.7 million recorded in Prepaid and other current assets and $7.0 million and $7.0 million in Other long-term assets as of December 31, 2017 and 2016 , respectively.

The following table summarizes the pre-tax gains (losses) recognized in Net income (loss) on our consolidated statements of operations resulting from changes in fair value of derivative instruments not designated as hedges charged directly to earnings (in thousands):

	Statement of Operations Classification	Year Ended December 31, 2017	2016	2015
Commodity derivatives	Cost of revenues (excluding depreciation)	$ (4,517)	$ (1,338)	$ 14,367
J. Aron repurchase obligation derivative	Cost of revenues (excluding depreciation)	436	(29,810)	12,654
Interest rate derivatives	Interest expense and financing costs, net	489	2,729	—

Note 13—Fair Value Measurements

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Purchase Price Allocation of Wyoming Refining

The fair values of the assets acquired and liabilities assumed as a result of the Wyoming Refining acquisition were estimated as of July 14, 2016 , the date of the acquisition, using valuation techniques described in notes (1) through (5) described below.

	Fair Value	Valuation Technique
	(in thousands)	
Net working capital	$ (11,092)	(1)
Property, plant, and equipment	254,367	(2)
Goodwill	66,449	(3)
Long-term debt	(68,136)	(4)
Other non-current liabilities	(32,222)	(5)
Total	$ 209,366	

(1) Current assets acquired and liabilities assumed were recorded at their net realizable value.

(2) The fair value of property, plant, and equipment was estimated using the cost approach. Under the cost approach, the total replacement cost of the property is determined based on industry sources with adjustments for regional factors. The total cost is then adjusted for depreciation based on the physical age of the assets and obsolescence. The fair value of the land was estimated using the sales comparison approach. Under this approach, the sales prices of similar properties are adjusted to account for differences in land characteristics. We consider this to be a Level 3 fair value measurement.

(3) The excess of the purchase price paid over the fair value of the identifiable assets acquired and liabilities assumed is allocated to goodwill.

(4) Long-term debt was recorded at carrying value. The carrying value of long-term debt approximated fair value due to its floating interest rate.

(5) Other non-current liabilities include environmental liabilities and the underfunded status of the Wyoming Refining defined benefit plan. The underfunded status of the defined benefit plan represents the difference between the fair value of the plan's assets and the projected benefit obligations. Environmental liabilities are based on management's best estimates of probable future costs using current available information. We consider this to be a Level 3 fair value measurement.

Purchase Price Allocation of Mid Pac

The fair values of the assets acquired and liabilities assumed as a result of the Mid Pac acquisition were estimated as of April 1, 2015 , the date of the acquisition, using valuation techniques described in notes (1) through (7) described below.

	Fair Value	Valuation Technique
	(in thousands)	
Net working capital	$ 15,989	(1)
Property, plant, and equipment	40,997	(2)
Land	34,800	(3)
Goodwill	26,942	(4)
Intangible assets	33,647	(5)
Other non-current assets	1,228	(7)
Deferred tax liability	(16,759)	(6)
Other non-current liabilities	(7,235)	(7)
Total	$ 129,609	

(1) Current assets acquired and liabilities assumed were recorded at their net realizable value.

(2) The fair value of the property, plant, and equipment was estimated using the cost approach. Under the cost approach, the total replacement cost of the property is determined based on industry sources with adjustments for regional factors. The total cost is then adjusted for depreciation based on the physical age of the assets and obsolescence. We consider this to be a Level 3 fair value measurement.

(3) The fair value of the land was estimated using the sales comparison approach. Under this approach, the sales prices of similar properties are adjusted to account for differences in land characteristics. We consider this to be a Level 3 fair value measurement.

(4) The excess of the purchase price paid over the fair value of the identifiable assets acquired and liabilities assumed is allocated to goodwill.

(5) The fair value of customer relationships was estimated using the Excess Earnings Method. Significant inputs used in this model include estimated revenue attributable to the customer relationship and estimated attrition rates. The fair value of the trade names and trademarks was estimated using the Relief from Royalty Method. Significant inputs used in this model include estimated revenue attributable to the trade names and trademarks and a royalty rate. We consider this to be a Level 3 fair value measurement.

(6) The deferred tax liability was determined based on the differences between the tax bases of the assets acquired and liabilities assumed and the values of those assets and liabilities recognized on our consolidated balance sheets as of the date of acquisition.

(7) Other non-current assets and liabilities were recorded at their estimated net present value. We consider this to be a Level 3 fair value measurement.

Investment in Laramie Energy

At December 31, 2015, we conducted an impairment test related to our equity investment in Laramie Energy . As a result of the decline in commodity prices during 2015, we concluded that our equity investment in Laramie Energy was impaired and recognized an other-than-temporary impairment charge of $41.1 million on our consolidated statement of operations for the year ended December 31, 2015. We primarily used a market approach to determine the fair value of our equity investment in Laramie Energy as of December 31, 2015. We used the income approach to corroborate our fair value measurement of Laramie Energy under the market approach. We consider this to be a Level 2 fair value measurement. During 2017 and 2016 , there was no impairment recorded in connection with our investment in Laramie Energy.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Common stock warrants

As of December 31, 2017 and 2016 , we had 354,350 common stock warrants outstanding. We estimate the fair value of our outstanding common stock warrants using the difference between the strike price of the warrant and the market price of our common stock, which is a Level 3 fair value measurement. As of December 31, 2017 , the warrants had a weighted-average exercise price of $0.09 and a remaining term of 4.67 years.

The estimated fair value of the common stock warrants was $19.21 and $14.49 per share as of December 31, 2017 and 2016 , respectively. Increases in the value of our common stock will increase the value of the common stock warrants. Likewise, decreases in the value of our common stock will result in a decrease in the value of the common stock warrants.

Derivative instruments

We utilize crude oil commodity derivative contracts to manage our price exposure in our inventory positions, future purchases of crude oil, future sales of refined products, and cost of crude oil consumed in the refining process. We utilize interest rate swaps to manage our interest rate risk. Please read Note 12—Derivatives for further information on derivatives.

We are obligated to repurchase the crude oil and refined products from J. Aron at the termination of the Supply and Offtake Agreements. We have determined that this obligation contains an embedded derivative, similar to forward purchase contracts of crude oil and refined products. As such, we have accounted for this embedded derivative at fair value with changes in the fair value recorded in Cost of revenues (excluding depreciation) on our consolidated statements of operations.

Upon redemption of our 5.00% Convertible Senior Notes on or after June 20, 2019 at our election, we are obligated to pay a make-whole premium equal to the present value of the remaining scheduled payments of interest on the 5.00% Convertible Senior Notes to be redeemed from the relevant redemption date to the maturity date of June 15, 2021 . We have determined that the redemption option and the related make-whole premium represent an embedded derivative that is not clearly and closely related to the 5.00% Convertible Senior Notes . As of December 31, 2017 and 2016 , this embedded derivative was deemed to have a *de minimis* fair value.

We classify financial assets and liabilities according to the fair value hierarchy. Financial assets and liabilities classified as Level 1 instruments are valued using quoted prices in active markets for identical assets and liabilities. These include our exchange traded futures. Level 2 instruments are valued using quoted prices for similar assets and liabilities in active markets and inputs other than quoted prices that are observable for the asset or liability. Our Level 2 instruments include OTC swaps and options. These commodity derivatives are valued using market quotations from independent price reporting agencies and commodity exchange price curves that are corroborated with market data. Level 3 instruments are valued using significant unobservable inputs that are not supported by sufficient market activity. The valuation of our J. Aron repurchase obligation derivative requires that we make estimates of the prices and differentials assuming settlement at the end of the reporting period. Estimates of the J. Aron settlement prices are based on observable inputs, such as Brent and WTI indices, and unobservable inputs, such as contractual price differentials as defined in the Supply and Offtake Agreements; therefore it is classified as a Level 3 instrument. We do not have other commodity derivatives classified as Level 3 at December 31, 2017 or 2016 . Please read Note 12—Derivatives for further information on derivatives.

Contingent consideration

The cash consideration for our acquisition of PHR was subject to an earnout provision. As of December 31, 2016, the earn-out measurement period was complete and our estimated liability no longer relies on forecasts and simulations. Prior to December 31, 2016, the liability was remeasured at the end of each reporting period using an estimate based on actual results to date and a Monte Carlo simulation analysis for future periods. Significant inputs used in the valuation model included estimated future gross margin, annual gross margin volatility, and a present value factor. We considered this to be a Level 3 fair value measurement. See Note 14—Commitments and Contingencies for further discussion.

Financial Statement Impact

Fair value amounts by hierarchy level as of December 31, 2017 and 2016 are presented gross in the tables below (in thousands):

	December 31, 2017					
	Level 1	Level 2	Level 3	Gross Fair Value	Effect of Counter-party Netting	Net Carrying Value on Balance Sheet (1)
Assets						
Commodity derivatives	$ 557	$ 21,907	$ —	$ 22,464	$ (19,650)	$ 2,814
Interest rate derivatives	—	3,810	—	3,810	—	3,810
Total	$ 557	$ 25,717	$ —	$ 26,274	$ (19,650)	$ 6,624
Liabilities						
Common stock warrants	$ —	$ —	$ (6,808)	$ (6,808)	$ —	$ (6,808)
Commodity derivatives	(596)	(19,093)	—	(19,689)	19,650	(39)
J. Aron repurchase obligation derivative	—	—	(19,564)	(19,564)	—	(19,564)
Total	$ (596)	$ (19,093)	$ (26,372)	$ (46,061)	$ 19,650	$ (26,411)

	December 31, 2016					
	Level 1	Level 2	Level 3	Gross Fair Value	Effect of Counter-party Netting	Net Carrying Value on Balance Sheet (1)
Assets						
Commodity derivatives	$ 190	$ 26,095	$ —	$ 26,285	$ (23,537)	$ 2,748
Interest rate derivatives	—	3,602	—	3,602	(64)	3,538
Total	$ 190	$ 29,697	$ —	$ 29,887	$ (23,601)	$ 6,286
Liabilities						
Common stock warrants	$ —	$ —	$ (5,134)	$ (5,134)	$ —	$ (5,134)
Commodity derivatives	(54)	(24,078)	—	(24,132)	23,537	(595)
J.Aron repurchase obligation derivative	—	—	(20,000)	(20,000)	—	(20,000)
Interest rate derivatives	—	(158)	—	(158)	64	(94)
Total	$ (54)	$ (24,236)	$ (25,134)	$ (49,424)	$ 23,601	$ (25,823)

(1) Does not include cash collateral of $7.2 million and $9.7 million as of December 31, 2017 and 2016 , respectively included on our consolidated balance sheets.

A roll forward of Level 3 derivative instruments measured at fair value on a recurring basis is as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Beginning balance	$ (25,134)	$ (25,867)	$ (21,254)
Settlements	—	16,810	7,691
Acquired	—	—	(2,844)
Total unrealized income (loss) included in earnings	(1,238)	(16,077)	(9,460)
Ending balance	$ (26,372)	$ (25,134)	$ (25,867)

The carrying value and fair value of long-term debt and other financial instruments as of December 31, 2017 and 2016 is as follows (in thousands):

	Carrying Value	Fair Value (1)
December 31, 2017		
5.00% Convertible Senior Notes due 2021 (3)	$ 95,486	$ 149,007
7.75% Senior Secured Notes due 2025	289,326	300,423
Common stock warrants	6,808	6,808
December 31, 2016		
Hawaii Retail Credit Agreement (2)	$ 93,853	$ 93,853
5.00% Convertible Senior Notes due 2021 (3)	91,029	122,229
Term Loan	57,426	62,367
Par Wyoming Holdings Term Loan (2)	65,908	65,908
Wyoming Refining Senior Secured Term Loan (2)	55,480	55,480
Wyoming Refining Senior Secured Revolver (2)	6,700	6,700
Common stock warrants	5,134	5,134

(1) The fair values of these instruments are considered Level 3 measurements in the fair value hierarchy with the exception of the fair value measurements of the 5.00% Convertible Senior Notes and the 7.75% Senior Secured Notes , which are considered Level 2 measurements as discussed below.

(2) Fair value approximated carrying value due to the debt's floating rate interest which approximates current market value.

(3) The carrying value of the 5.00% Convertible Senior Notes excludes the fair value of the equity component, which was classified as equity upon issuance.

We estimated the fair value of the Term Loan using a discounted cash flow analysis and an estimate of the current yield of 11.06% as of December 31, 2016 by reference to market interest rates for term debt of comparable companies.

The fair value of the 5.00% Convertible Senior Notes was determined by aggregating the fair value of the liability and equity components of the notes. The fair value of the liability component of the 5.00% Convertible Senior Notes was determined using a discounted cash flow analysis in which the projected interest and principal payments were discounted at an estimated market yield for a similar debt instrument without the conversion feature. The equity component was estimated based on the Black-Scholes model for a call option with strike price equal to the conversion price, a term matching the remaining life of the 5.00% Convertible Senior Notes , and an implied volatility based on market values of options outstanding as of December 31, 2017 . The fair value of the 5.00% Convertible Senior Notes is considered a Level 2 measurement in the fair value hierarchy.

The fair value of the 7.75% Senior Secured Notes was determined using a market approach based on quoted prices. Because the 7.75% Senior Secured Notes may not be actively traded, the inputs used to measure the fair value are classified as Level 2 inputs within the fair value hierarchy.

The fair value of all non-derivative financial instruments included in current assets, including cash and cash equivalents, restricted cash, and trade accounts receivable, current liabilities, and accounts payable approximate their carrying value due to their short term nature.

Note 14—Commitments and Contingencies

In the ordinary course of business, we are a party to various lawsuits and other contingent matters. We establish accruals for specific legal matters when we determine that the likelihood of an unfavorable outcome is probable and the loss is reasonably estimable. It is possible that an unfavorable outcome of one or more of these lawsuits or other contingencies could have a material impact on our financial condition, results of operations, or cash flows.

Tesoro Earnout Dispute

On June 17, 2013, a wholly owned subsidiary of Par entered into a membership interest purchase agreement with Andeavor, formerly known as Tesoro Corporation (“Tesoro”), pursuant to which it purchased all of the issued and outstanding membership interests in Tesoro Hawaii, LLC, an entity that was renamed Hawaii Independent Energy, LLC, and thereafter renamed Par Hawaii Refining, LLC. The cash consideration for the acquisition is subject to an earn-out provision during the years 2014-2016, subject to, among other things, an annual earn-out cap of $20 million and an overall cap of $40 million . During 2016, we paid Tesoro a total of $16.8 million to settle the 2014 and 2015 earn-out periods. Tesoro has disputed our calculation of the 2015 and 2016 earn-out amounts and has asserted that it is entitled to an additional earn-out amount of $4.3 million for the 2015 earn-out period and a total earn-out amount of $8.3 million for the 2016 earn-out period. If we and Tesoro are unable to agree on the calculation of the 2015 and 2016 earn-out amounts, the dispute will be resolved in accordance with the dispute resolution provisions set forth in the membership interest purchase agreement to determine the amounts owed, if any. The Company disputes that any additional amounts are due and intends to vigorously defend itself in connection with the resolution of Tesoro’s claims. The parties have agreed to attend non-binding mediation on March 22, 2018.

Mid Pac Earnout and Indemnity Dispute

Pursuant to a Stock Purchase Agreement dated August 3, 2011 and amended October 25, 2011 (the “SPA”), Mid Pac purchased all the issued and outstanding stock of Inter Island Petroleum, Inc. (“Inter Island”) from Brian J. and Wendy Barbata (collectively, the “Barbatas”). The SPA provides for an earn-out payment to be made to the Barbatas in an amount equal to four times the amount by which the average of Inter Island’s earnings before interest, taxes, depreciation, and amortization during the relevant earn-out period exceeds $3.5 million . The earn-out payment is capped at a maximum of $4.5 million . Mid Pac contends that there are no amounts owed to the Barbatas for the earn-out period, while the Barbatas contend they are entitled to $4.5 million . Mid Pac intends to vigorously oppose any such claims.

Any claims by the Barbatas may be offset by Mid Pac ’s claims for indemnification under the SPA. By letters dated December 31, 2013 and April 25, 2014, Mid Pac has asserted indemnification claims against the Barbatas exceeding $1 million with respect to environmental losses arising from certain terminals operated by Inter Island and its subsidiaries. The Barbatas have disputed such claims. Arbitration for the earn-out and indemnification claims is scheduled to commence on November 27, 2018.

United Steelworkers Union Dispute

A portion of our employees at the Hawaii refinery are represented by the United Steelworkers Union (“USW”). On March 23, 2015, the union ratified a four-year extension of the collective bargaining agreement. On January 13, 2016, the USW filed a claim against PHR before the United States National Labor Relations Board (the “NLRB”) alleging a refusal to bargain collectively and in good faith. On March 29, 2016, the NLRB deferred final determination on the USW charge to the grievance/arbitration process under the extant collective bargaining agreement. Arbitration has been scheduled for the week of October 1, 2018. PHR denies the USW’s allegations and intends to vigorously defend itself in connection with such claim in the grievance/arbitration process and any subsequent proceeding before the NLRB.

Environmental Matters

Like other petroleum refiners and exploration and production companies, our operations are subject to extensive and periodically-changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Many of these regulations are becoming increasingly stringent and the cost of compliance can be expected to increase over time.

Periodically, we receive communications from various federal, state, and local governmental authorities asserting violations of environmental laws and/or regulations. These governmental entities may also propose or assess fines or require corrective actions for these asserted violations. We intend to respond in a timely manner to all such communications and to take appropriate corrective action. Except as disclosed below, we do not anticipate that any such matters currently asserted will have a material impact on our financial condition, results of operations, or cash flows.

Wyoming refinery

Our Wyoming refinery is subject to a number of consent decrees, orders, and settlement agreements involving the U.S. Environmental Protection Agency ("EPA") and/or the Wyoming Department of Environmental Quality, some of which date back to the late 1970s and several of which remain in effect, requiring further actions at the Wyoming refinery. The largest cost component arising from these various decrees relates to the investigation, monitoring, and remediation of soil, groundwater, surface water and sediment contamination associated with the facility's historic operations. Investigative work by Wyoming Refining and negotiations with the relevant agencies as to remedial approaches remain ongoing on a number of aspects of the contamination, meaning that investigation, monitoring, and remediation costs are not reasonably estimable for some elements of these efforts. As of December 31, 2017 , we have accrued $18.2 million for the well-understood components of these efforts based on current information, approximately one-third of which we expect to incur in the next 5 years , with the remainder being incurred over approximately 30 years .

Additionally, we believe the Wyoming refinery will need to modify or close a series of wastewater impoundments in the next several years and replace those impoundments with a new wastewater treatment system. Based on preliminary information, reasonable estimates we have received suggest costs of approximately $11.6 million to design and construct a new wastewater treatment system.

Finally, among the various historic consent decrees, orders, and settlement agreements into which Wyoming Refining has entered, there are several penalty orders associated with exceedances of permitted limits by the Wyoming refinery's wastewater discharges. Although the frequency of these exceedances appears to be declining over time, Wyoming Refining may become subject to new penalty enforcement action in the next several years, which could involve penalties in excess of $100,000 . Moreover, in November 2016, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") conducted an integrated inspection of the products pipeline acquired in the WRC Acquisition. As a result of compliance violations identified during the inspection, the Wyoming refinery was assessed a civil penalty of $279 thousand in December 2017, which was paid in January 2018.

Regulation of Greenhouse Gases

The EPA regulates greenhouse gases ("GHG") under the federal Clean Air Act ("CAA"). New construction or material expansions that meet certain GHG emissions thresholds will likely require that, among other things, a GHG permit be issued in accordance with the federal CAA regulations and we will be required in connection with such permitting to undertake a technology review to determine appropriate controls to be implemented with the project in order to reduce GHG emissions.

Furthermore, the EPA is currently developing refinery-specific GHG regulations and performance standards that are expected to impose GHG emission limits and/or technology requirements. These control requirements may affect a wide range of refinery operations. Any such controls could result in material increased compliance costs, additional operating restrictions for our business, and an increase in the cost of the products we produce, which could have a material adverse effect on our financial condition, results of operations, or cash flows.

On September 29, 2015, the EPA announced a final rule updating standards that control toxic air emissions from petroleum refineries, addressing, among other things, flaring operations, fenceline air quality monitoring, and additional emission reductions from storage tanks and delayed coking units. Affected existing sources will be required to comply with the new requirements no later than 2018, with certain refiners required to comply earlier depending on the relevant provision and refinery construction date. We do not anticipate that compliance with this rule will have a material impact on our financial condition, results of operations, or cash flows.

In 2007, the State of Hawaii passed Act 234, which required that GHG emissions be rolled back on a statewide basis to 1990 levels by the year 2020. Although delayed, the Hawaii Department of Health has issued regulations that would require each major facility to reduce CO_2 emissions by 16% by 2020 relative to a calendar year 2010 baseline (the first year in which GHG emissions were reported to the EPA under 40 CFR Part 98). Those rules are pending final approval by the Hawaii State Government. The Hawaii refinery's capacity to reduce fuel use and GHG emissions is limited. However, the state's pending regulation allows, and the Hawaii refinery expects to be able to demonstrate, that additional reductions are not cost-effective or necessary in light of the state's current GHG inventory and future year projections. The pending regulation allows for "partnering" with other facilities (principally power plants) that have already dramatically reduced greenhouse emissions or are on schedule to reduce CO_2 emissions in order to comply with the state's Renewable Portfolio Standards.

Fuel Standards

In 2007, the U.S. Congress passed the Energy Independence and Security Act of 2007 (the "EISA") that, among other things, sets a target fuel economy standard of 35 miles per gallon for the combined fleet of cars and light trucks in the U.S. by model year 2020 and contained a second Renewable Fuel Standard (the "RFS2"). In August 2012, the EPA and National Highway Traffic Safety Administration jointly adopted regulations that establish an average industry fuel economy of 54.5 miles per gallon by model year 2025. The RFS2 requires an increasing amount of renewable fuel usage, up to 36 billion gallons by 2022. In the near term, the RFS2 will be satisfied primarily with fuel ethanol blended into gasoline. The RFS2 may present production and logistics challenges for both the renewable fuels and petroleum refining and marketing industries in that we may have to enter into arrangements with other parties or purchase credits from the EPA to meet our obligations to use advanced biofuels, including biomass-based diesel and cellulosic biofuel, with potentially uncertain supplies of these new fuels.

In October 2010, the EPA issued a partial waiver decision under the CAA to allow for an increase in the amount of ethanol permitted to be blended into gasoline from 10% ("E10") to 15% ("E15") for 2007 and newer light duty motor vehicles. In January 2011, the EPA issued a second waiver for the use of E15 in vehicles model years 2001- 2006. There are numerous issues, including state and federal regulatory issues, that need to be addressed before E15 can be marketed on a large scale for use in traditional gasoline engines. Consequently, unless either the state or federal regulations are revised, RINs will be required to fulfill the federal mandate for renewable fuels.

In March 2014, the EPA published a final Tier 3 gasoline standard that lowers the allowable sulfur level in gasoline to 10 parts per million ("ppm") and also lowers the allowable benzene, aromatics, and olefins content of gasoline, with the most recent rulemaking addressing certain technical corrections and clarifications effective June 21, 2016. The effective date for the new standard was January 1, 2017, however, approved small volume refineries have until January 1, 2020 to meet the standard. Our Hawaii refinery is required to comply with Tier 3 gasoline standards within 30 months of June 21, 2016, the date our Hawaii refinery was disqualified from small volume refinery status. On March 19, 2015, the EPA confirmed the small volume refinery status of our Wyoming refinery.

There will be compliance costs and uncertainties regarding how we will comply with the various requirements contained in the EISA and other fuel-related regulations. Along with credit and trading options, potential capital upgrades for the Hawaii and Wyoming refineries are being evaluated. We may also experience a decrease in demand for refined petroleum products due to an increase in combined fleet mileage or due to refined petroleum products being replaced by renewable fuels.

Environmental Agreement

On September 25, 2013 , Par Petroleum, LLC (formerly Hawaii Pacific Energy, a wholly owned subsidiary of Par created for purposes of the PHR acquisition), Tesoro, and PHR entered into an Environmental Agreement ("Environmental Agreement") that allocated responsibility for known and contingent environmental liabilities related to the acquisition of PHR , including the Consent Decree as described below.

Consent Decree

On July 18, 2016, PHR and subsidiaries of Tesoro entered into a consent decree with the EPA, the U.S. Department of Justice ("DOJ"), and other state governmental authorities concerning alleged violations of the federal CAA related to the ownership and operation of multiple facilities owned or formerly owned by Tesoro and its affiliates ("Consent Decree"), including our Hawaii refinery. As a result of the Consent Decree, PHR expanded its planned 2016 Hawaii refinery turnaround to undertake additional capital improvements to reduce emissions of air pollutants and to provide for certain nitrogen oxide and sulfur dioxide emission controls and monitoring required by the Consent Decree. Although the turnaround was completed during the third quarter of 2016, work related to the Consent Decree is ongoing. This work subjects us to risks associated with engineering, procurement, and construction of improvements and repairs to our facilities and related penalties and fines to the extent applicable deadlines under the Consent Decree are not satisfied, as well as risks related to the performance of equipment required by, or affected by, the Consent Decree. Each of these risks could have a material adverse effect on our business, financial condition, or results of operations.

We estimate the cost of compliance with the Consent Decree to be approximately $30.0 million . However, Tesoro is responsible under the Environmental Agreement for directly paying, or reimbursing PHR , for all reasonable third-party capital expenditures incurred pursuant to the Consent Decree to the extent related to acts or omissions prior to the date of the closing of the PHR acquisition. Tesoro is obligated to pay all applicable fines and penalties related to the Consent Decree.

Through December 31, 2017 , Tesoro has reimbursed us for $12.1 million of our total capital expenditures of $12.9 million incurred in connection with the Consent Decree. Net capital expenditures and reimbursements related to the Consent Decree for the year ended December 31, 2017 and 2016 are presented within Capital expenditures on our consolidated statement of cash flows for the related periods.

Indemnification

In addition to its obligation to reimburse us for capital expenditures incurred pursuant to the Consent Decree, Tesoro agreed to indemnify us for claims and losses arising out of related breaches of Tesoro's representations, warranties, and covenants in the Environmental Agreement, certain defined "corrective actions" relating to pre-existing environmental conditions, third-party claims arising under environmental laws for personal injury or property damage arising out of or relating to releases of hazardous materials that occurred prior to the date of the closing of the PHR acquisition, any fine, penalty, or other cost assessed by a governmental authority in connection with violations of environmental laws by PHR prior to the date of the closing of the PHR acquisition, certain groundwater remediation work, fines, or penalties imposed on PHR by the Consent Decree related to acts or omissions of Tesoro prior to the date of the closing of the PHR acquisition, and claims and losses related to the Pearl City Superfund Site.

Tesoro's indemnification obligations are subject to certain limitations as set forth in the Environmental Agreement. These limitations include a deductible of $1.0 million and a cap of $15.0 million for certain of Tesoro's indemnification obligations related to certain pre-existing conditions as well as certain restrictions regarding the time limits for submitting notice and supporting documentation for remediation actions.

Recovery Trusts

We emerged from the reorganization of Delta Petroleum Corporation ("Delta") on August 31, 2012 ("Emergence Date") when the plan of reorganization ("Plan") was consummated. On the Emergence Date, we formed the Delta Petroleum General Recovery Trust ("General Trust"). The General Trust was formed to pursue certain litigation against third parties, including preference actions, fraudulent transfer and conveyance actions, rights of setoff and other claims, or causes of action under the U.S. Bankruptcy Code and other claims and potential claims that the Debtors hold against third parties.

As of December 31, 2017 , two related claims totaling approximately $22.4 million remained to be resolved by the trustee for the General Trust and we have accrued approximately $0.5 million representing the estimated value of claims remaining to be settled which are deemed probable and estimable at period end.

One of the two remaining claims was filed by the U.S. Government for approximately $22.4 million relating to ongoing litigation concerning a plugging and abandonment obligation in Pacific Outer Continental Shelf Lease OCS-P 0320, comprising part of the Sword Unit in the Santa Barbara Channel, California. The second unliquidated claim, which is related to the same plugging and abandonment obligation, was filed by Noble Energy Inc., the operator and majority interest owner of the Sword Unit. We believe the probability of issuing stock to satisfy the full claim amount is remote, as the obligations upon which such proof of claim is asserted are joint and several among all working interest owners and Delta, our predecessor, only owned an approximate 3.4% aggregate working interest in the unit.

The settlement of claims is subject to ongoing litigation and we are unable to predict with certainty how many shares will be required to satisfy all claims. Pursuant to the Plan, allowed claims are settled at a ratio of 54.4 shares per $1,000 of claim. See Note 21—Subsequent Events for further discussion.

Capital Leases

Within our retail segment, we have capital lease obligations related primarily to the leases of five retail stations with generally two years remaining on the current term and four five-year renewal options . Minimum annual lease payments including interest, for capital leases are as follows (in thousands):

2018	$	863
2019		703
2020		167
2021		56
2022		—
Thereafter		—
Total minimum lease payments		1,789
Less amount representing interest		86
Total minimum rental payments	$	1,703

Operating Leases

We have various cancelable and noncancelable operating leases related to land, vehicles, office and retail facilities, railcars, barges, and other facilities used in the storage, transportation, and sale of crude oil and refined products. The majority of the future lease payments relate to retail stations and facilities used in the storage, transportation, and sale of crude oil and refined products. We have operating leases for most of our retail stations with an average of 5 years remaining and generally containing renewal options and escalation clauses. Leases for facilities used in the storage, transportation, and sale of crude oil and refined products have various expiration dates extending to 2078 .

Minimum annual lease payments for operating leases to which we are legally obligated and having initial or remaining non-cancelable lease terms in excess of one year are as follows (in thousands):

2018	$	16,453
2019		12,305
2020		8,649
2021		7,332
2022		6,275
Thereafter		29,668
Total minimum rental payments	$	80,682

Rent expense for the years ended December 31, 2017 , 2016 , and 2015 was approximately $41.2 million , $39.6 million , and $17.7 million , respectively.

Major Customers

For the year ended December 31, 2017 , we had one customer in our refining segment that accounted for 10% of our consolidated revenue. No other customer accounted for more than 10% of our consolidated revenues during the years ended December 31, 2017 , 2016 , and 2015 .

Note 15—Stockholders' Equity

Common Stock

Our certificate of incorporation contains restrictions on the transfer of certain of our securities in order to preserve the net operating loss carryovers, capital loss carryovers, general business credit carryovers, alternative minimum tax credit carryovers, and foreign tax credit carryovers, as well as any “net unrealized built-in loss” within the meaning of Section 382 of the Internal Revenue Service Code, of us or any direct or indirect subsidiary thereof. These restrictions include provisions regarding approval by our Board of Directors of transfers of common stock by holders of five percent or more of the outstanding common stock. Our debt agreements restrict the payment of dividends.

On September 22, 2016 , we issued approximately 4 million shares of our common stock to certain pre-existing investors and other investors in the Rights Offering at a purchase price of $12.25 per share. The gross proceeds from the Rights Offering were approximately $49.9 million , before deducting expenses of approximately $0.9 million , for net proceeds of approximately $49.0 million . The net proceeds from the Rights Offering were used to repay all accrued and unpaid interest and a portion of the outstanding principal amount on the Bridge Notes.

On November 25, 2015 , we issued an aggregate of 3.4 million shares of our common stock to certain pre-existing investors and other investors in a registered direct offering (the “Offering”) at a purchase price of $22.00 per share. The total gross proceeds from the Offering were approximately $74.8 million , before deducting expenses of approximately $1.0 million , for net proceeds of approximately $73.8 million .

Registration Rights Agreements

In connection with our emergence from bankruptcy on August 31, 2012, we entered into a registration rights agreement (“Registration Rights Agreement”) providing the stockholders party thereto (“Stockholders”) with certain registration rights.

The Registration Rights Agreement states that at any time after the consummation of a qualified public offering, any Stockholder or group of Stockholders that, together with its or their affiliates, holds more than fifteen percent of the Registrable

Shares (as defined in the Registration Rights Agreement), will have the right to require us to file with the SEC a registration statement for a public offering of all or part of its Registrable Shares (each a "Demand Registration"), by delivery of written notice to the company (each, a "Demand Request").

Within 90 days after receiving the Demand Request, we must file with the SEC the registration statement with respect to the Demand Registration, subject to certain limitations as set forth in the Registration Rights Agreement. We are required to use commercially reasonable efforts to cause the registration statement to be declared effective as soon as practicable after such filing.

In addition, subject to certain exceptions, if we propose to register any class of common stock for sale to the public, we are required, subject to certain conditions, to include all Registrable Shares with respect to which we have received written requests for inclusion.

In connection with the closing of a private placement, we entered into an additional registration rights agreement with the purchasers of the shares. Under this registration rights agreement, we agreed to file a registration statement relating to the shares of common stock with the SEC within 60 days after the closing date of the sale which would be declared effective within 180 days of the closing date of the sale. We also agreed to use commercially reasonable efforts to keep the registration statement effective until the earliest to occur of (i) the disposition of all registrable securities, (ii) the availability under Rule 144 of the Securities Act of 1933, as amended, for each holder of registrable securities to immediately freely resell such registrable securities without volume restrictions, or (iii) the third anniversary of the effective date of the registration statement.

This registration rights agreement also provides the right for a holder or group of holders of more than $50 million of registrable securities to demand that we conduct an underwritten public offering of the registrable securities. However, the demanding holders are limited to a total of three such underwritten offerings, with no more than one demand request for an underwritten offering made in any 365 day period. Additionally, this registration rights agreement contains customary indemnification rights and obligations for both us and the holders of registrable securities.

If this registration statement does not remain effective for the applicable effectiveness period described above then from that date until cured, we must pay, as liquidated damages and not as a penalty, an amount in cash equal to 0.25% of the purchaser's allocated purchase price per calendar month, not to exceed 0.75% of the allocated purchase price.

The registration rights granted in each rights agreement are subject to customary indemnification and contribution provisions, as well as customary restrictions such as suspension periods and, if a registration is for an underwritten offering, limitations on the number of shares to be included in the underwritten offering imposed by the managing underwriter.

In connection with the completion of the Company's private unregistered offering of its 5.00% Convertible Senior Notes , the Company entered into a Registration Rights Agreement (the "Convertible Notes Registration Rights Agreement"), dated as of June 21, 2016, with the initial purchasers in the offering of the 5.00% Convertible Senior Notes . The Convertible Notes Registration Rights Agreement requires the Company (i) to file with the SEC a shelf registration statement covering resales of the shares of common stock, if any, issuable upon conversion of the 5.00% Convertible Senior Notes and in respect of any make-whole premium, (ii) to use its best efforts to cause, if not a well-known seasoned issuer, such shelf registration statement to be declared effective by the SEC within 180 days after June 21, 2016, and (iii) to use its best efforts to keep such shelf registration statement effective until the earlier of (A) the 120th calendar day immediately following the maturity date of the 5.00% Convertible Senior Notes or (B) the date on which there are no longer outstanding any 5.00% Convertible Senior Notes or restricted shares of the common stock that have been received upon conversion of the 5.00% Convertible Senior Notes or in respect of any make-whole premium.

If the Company does not fulfill its obligations under the Convertible Notes Registration Rights Agreement, it will be required to pay the holders of the 5.00% Convertible Senior Notes liquidated damages in the form of additional interest on the 5.00% Convertible Senior Notes . Such additional interest will accrue at a rate per year equal to: (i) 0.25% of the principal amount of the 5.00% Convertible Senior Notes to, and including, the 90th day following such registration default and (ii) 0.50% of the principal amount of the 5.00% Convertible Senior Notes from, and after, the 91st day following such registration default. In no event will the liquidated damages exceed 0.50% per year.

In connection with the issuance by the Company of its 2.50% convertible subordinated bridge notes (the "Bridge Notes"), the Company entered into a registration rights agreement (the "Bridge Notes Registration Rights Agreement"), dated as of July 14, 2016 with the purchasers of the Bridge Notes. The Bridge Notes Registration Rights Agreement required the Company to file with the SEC a shelf registration statement covering resales of the shares of common stock, if any, issuable upon conversion of the Bridge Notes, (ii) to use its commercially reasonable efforts to cause such shelf registration statement to be declared effective by the SEC no later than (A) the earlier of December 14, 2016 or 60 days after the filing deadline for the shelf registration statement or (B) if earlier, five business days after the date on which the SEC informs the Company that it will not review the shelf registration statement, and (iii) to use its commercially reasonable efforts to keep such shelf registration statement effective until the earlier of (A) the date on which all of such shares have been sold, (B) the date on which such shares may be sold without volume restrictions under Rule 144 of the Securities Act of 1933, as amended, or (C) the third anniversary of the effective date of such shelf registration statement.

If the Company does not fulfill its obligations under the Bridge Notes Registration Rights Agreement with respect to the filing deadline, effectiveness deadline, or effectiveness period of a registration statement, it will be required to pay the holders of the Bridge Notes liquidated damages in an amount in cash equal to 1.00% of such holder's "Allocated Purchase Price," which is the amount effectively paid by such holder for the Common Stock acquired upon conversion of the Bridge Notes, per calendar month or portion thereof prior to the cure of such event of default. The maximum payment of liquidated damages to any such holder associated with all events of default will not exceed 5.00% of such holder's Allocated Purchase Price.

Incentive Plans

Our incentive compensation plans are described below.

Long Term Incentive Plan

On December 20, 2012, our Board of Directors ("Board") approved the Par Petroleum Corporation 2012 Long Term Incentive Plan ("Incentive Plan" or "LTIP"). Under the Incentive Plan, the Board, or a committee of the Board, may grant incentive stock options, nonstatutory stock options, restricted stock, and restricted stock units to directors and other employees or those of our subsidiaries. On February 16, 2016, the Board approved the amendment and restatement of the Incentive Plan to increase the number of shares issuable under the Amended and Restated LTIP. The Company's shareholders ratified the amended and restated Incentive Plan on June 2, 2016. The maximum number of shares that may be granted under the LTIP is 4.0 million shares of common stock. At December 31, 2017 , 0.8 million shares were available for future grants and awards under the LTIP.

Restricted stock and restricted stock units awarded under the Incentive Plan are subject to restrictions, terms, and conditions, including forfeitures, as may be determined by the Board. During the period in which such restrictions apply, unless specifically provided otherwise in accordance with the terms of the Incentive Plan, the recipient of the restricted stock would be the record owner of the shares and have all of the rights of a stockholder with respect to the shares, including the right to vote and the right to receive dividends or other distributions made or paid with respect to the shares. The recipient of restricted stock units shall not have any of the rights of a stockholder of the Company; the Compensation Committee of the Board shall be entitled to specify with respect to any restricted stock unit award that upon the payment of a dividend by the Company, the Company will hold in escrow an amount in cash equal to the dividend that would have been paid on the restricted stock units had they been converted into the same number of shares of common stock and held by the recipient on that date. Upon adjustment and vesting of the restricted stock unit, any cash payment due with respect to such dividends shall be made to the recipient. The fair value of the restricted stock and stock units is generally determined based upon the quoted market price of our common stock on the date of grant. These awards generally vest ratably over a four-year period.

Stock options are issued with an exercise price equal to the fair market value of our common stock on the date of grant and are subject to such other terms and conditions as may be determined by the Board. The options generally expire eight years from the grant date, unless granted by the Board for a shorter term. Option grants generally vest ratably over a four -year period.

Stock Purchase Plan

On June 12, 2014, the Board adopted a Stock Purchase Plan (as amended, the "SPP") plan. The SPP is limited to the Company's qualifying executive officers and directors who qualify as accredited investors under Rule 501(a) of the Securities Act of 1933, as amended. The SPP provides that each participant may, subject to compliance with securities laws and other regulations and only during "window periods" as described in our insider trading policy as in effect from time to time, until the later to occur of (a) December 31, 2015 or (b) the eighteen month anniversary of the date that the participant commenced his or her employment or service with us, purchase, in a single transaction, up to $1 million of shares of our common stock ("the SPP Shares") at a per share purchase price equal to the closing price of the common stock on the date of purchase. The sale or transfer of the SPP Shares by such participant would be limited for the earlier of (i) two years from the date of purchase or (ii) the termination of the participant's service with us or any affiliates for any reason. Additionally, the SPP provides that each purchasing participant will be granted a number of shares of restricted common stock under the Incentive Plan equal to 20% of the SPP Shares purchased with 50% of the restricted common stock vesting on each of the two annual anniversaries of the date of grant. Each purchasing participant will also be granted nonstatutory stock options with a 5 -year term to purchase a number of shares of common stock under the Incentive Plan (with an exercise price equal to the Fair Market Value as defined in the Incentive Plan on the date of grant) equal to certain specified percentages of the SPP Shares purchased based on a Black-Scholes model with 50% of the options vesting on each of the two annual anniversaries of the date of grant. Such percentages are as follows: 50% for a non-employee chairman of the Board, 35% for non-employee members of the Board, and 50% - 70% for executive officers.

The following table summarizes our compensation costs recognized in General and administrative expense (excluding depreciation) and Operating expense (excluding depreciation) under the Incentive Plan and Stock Purchase Plan (in thousands):

	Years Ended December 31,		
	2017	2016	2015
Restricted Stock Awards	$ 4,263	$ 2,975	$ 3,692
Restricted Stock Units	$ 502	$ 1,255	$ —
Stock Option Awards	$ 2,439	$ 2,352	$ 1,477

Restricted Stock Awards and Restricted Stock Units

The following table summarizes our restricted stock activity, including performance restricted stock units, (in thousands, except per share amounts):

	Shares	Weighted-Average Grant Date Fair Value
Unvested balance at December 31, 2016	436	$ 17.83
Granted	323	$ 15.25
Vested	(207)	$ 18.77
Forfeited	(9)	$ 16.44
Unvested balance at December 31, 2017	543	$ 16.23

The total fair value of restricted stock and restricted stock units that vested during the years ended December 31, 2017 , 2016 , and 2015 was $4.0 million , $3.6 million , and $4.5 million , respectively. The estimated weighted-average grant-date fair value per share of restricted stock and restricted stock units granted during the years ended December 31, 2017 , 2016 , and 2015 was $15.25 , $17.32 , and $18.24 , respectively.

As of December 31, 2017 , 2016 , and 2015 , there was approximately $5.7 million , $6.2 million , and $7.1 million , of total unrecognized compensation costs related to restricted stock awards and restricted stock units, which are expected to be recognized on a straight-line basis over a weighted-average period of 2.39 years, 2.50 years, and 2.91 years, respectively.

During the year ended December 31, 2017 , we granted 45 thousand performance restricted stock units to executive officers. These performance restricted stock units had a fair value of approximately $0.7 million and are subject to certain annual performance targets as defined by our Board of Directors.

As of December 31, 2017 , there were approximately $0.4 million of total unrecognized compensation costs related to the performance restricted stock units, which are expected to be recognized on a straight-line basis over a weighted-average period of 2.16 years.

Stock Option Grants

The fair value of each option is estimated on the grant date using the Black-Scholes option pricing model. The expected term represents the period of time that options are expected to be outstanding and is based upon the term of the option. The expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the expected term of the award. We do not use an expected dividend yield in our fair value measurement as we are restricted from payment of dividends. The risk-free rate is the implied yield available on U.S. Treasury securities with a remaining term equal to the expected term of the option at the date of grant. The weighted-average assumptions used to measure stock options granted during 2017 , 2016 , and 2015 are presented below.

	2017	2016	2015
Expected life from date of grant (years)	5.3	4.4	6.4
Expected volatility	42.0%	39.8%	35.0%
Expected dividend yield	—%	—%	—%
Risk-free interest rate	1.97%	1.16%	1.81%

The following table summarizes our stock option activity (in thousands, except per share amounts):

	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term in Years	Aggregate Intrinsic Value
Outstanding balance at December 31, 2016	1,743	$ 20.13	6.2	$ —
Issued	239	15.03		
Exercised	—	—		
Forfeited / canceled	(3)	15.15		
Outstanding balance at December 31, 2017	1,979	$ 19.52	5.5	$ 1,431
Exercisable, end of year	1,094	$ 19.51	4.3	$ 1,329

The estimated weighted-average grant-date fair value per share of options granted during the year ended December 31, 2017 , 2016 , and 2015 was $5.81 , $3.79 , and $8.36 , respectively.

As of December 31, 2017 and 2016 , there were approximately $3.5 million and $4.5 million , respectively, of total unrecognized compensation costs related to stock option awards, that are expected to be recognized on a straight-line basis over a weighted-average period of 1.74 and 2.84 years, respectively.

Note 16—Benefit Plans

Defined Contribution Plan

We maintain two defined contribution plans for our employees. All eligible employees may participate in one of these plans, either immediately or after one year of service, depending on the plan. We match employee contributions up to a maximum of 6% of the employee's eligible compensation. Vesting percentages associated with the employer contributions range from 0% to 100% , depending on the plan and the number of years of service. For the years ended December 31, 2017 , 2016 , and 2015 , we made contributions to the plans totaling approximately $3.6 million , $3.2 million , and $1.4 million , respectively.

Defined Benefit Plan

We maintain a defined benefit pension plan (the “Benefit Plan”) covering substantially all our Wyoming Refining employees. Benefits are based on years of service and the employee’s highest average compensation received during five consecutive years of the last ten years of employment. Our funding policy is to contribute annually an amount equal to the pension expense, subject to the minimum funding requirements of the Employee Retirement Income Security Act of 1974 and the tax deductibility of such contributions.

In December 2016, the Benefit Plan was amended (the "Plan Amendment") to freeze all future benefit accruals for salaried plan participants. The Plan Amendment reduced the projected benefit obligation by $3.1 million as of December 31, 2016. The curtailment gain of $3.1 million was recognized as reduction of Operating expense (excluding depreciation) in our consolidated statement of operations for the year ended December 31, 2016.

The changes in the projected benefit obligation and the fair value of plan assets of our Benefit Plan for the year ended December 31, 2017 and the period from July 14, 2016 to December 31, 2016 were as follows (in thousands):

	2017	2016
Changes in projected benefit obligation:		
Projected benefit obligation as of the beginning of the period	$ 28,914	$ 34,319
Service cost	614	668
Interest cost	1,192	598
Plan amendment	—	(3,067)
Actuarial (gain) loss	1,091	(2,436)
Benefits paid	(934)	(1,168)
Projected benefit obligation as of December 31	$ 30,877	$ 28,914
Changes in fair value of plan assets:		
Fair value of plan assets as of the beginning of the period	$ 21,345	$ 22,067
Actual return on plan assets	3,050	446
Employer contributions	—	—
Benefits paid	(934)	(1,168)
Fair value of plan assets as of December 31	$ 23,461	$ 21,345

The underfunded status of our Benefit Plans is recorded within Other liabilities in our consolidated balance sheets. The reconciliation of the underfunded status of our Benefit Plans of December 31, 2017 and 2016 was as follows:

	2017	2016
Projected benefit obligation	$ 30,877	$ 28,914
Fair value of plan assets	23,461	21,345
Underfunded status	$ 7,416	$ 7,569
Gross amounts recognized in accumulated other comprehensive income: (1)		
Net actuarial gain	$ 2,965	$ 2,196

(1) As of December 31, 2017 , we had no amounts recorded in accumulated other comprehensive income that are expected to be amortized into net periodic benefit cost in 2018 .

Weighted-average assumptions used to measure our projected benefit obligation as of December 31, 2017 and 2016 and net periodic benefit costs for the year ended December 31, 2017 and the period from July 14, 2016 to December 31, 2016 are as follows:

	2017	2016
Projected benefit obligation:		
Discount rate (1)	3.65%	4.20%
Rate of compensation increase	3.00%	4.30%
Net periodic benefit costs:		
Discount rate (1)	4.20%	3.80%
Expected long-term rate of return (2)	6.25%	7.00%
Rate of compensation increase	4.30%	4.03%

(1) In determining the discount rate, we use yields on high-quality fixed income investments with payments matched to the estimated distributions of benefits from our plans.

(2) The expected long-term rate of return is based on a blend of historic returns of equity and debt securities.

The net periodic benefit cost (credit) for the year ended December 31, 2017 and the period from July 14, 2016 to December 31, 2016 includes the following components:

	2017	2016
Components of net periodic benefit cost (credit):		
Service cost	$ 614	$ 668
Interest cost	1,192	598
Expected return on plan assets	(1,189)	(686)
Plan amendment effect	—	(3,067)
Net periodic benefit cost (credit)	$ 617	$ (2,487)

The weighted-average asset allocation at December 31, 2017 is as follows:

	Target	Actual
Asset category:		
Equity securities	60%	59%
Debt securities	30%	32%
Real estate	10%	9%
Total	100%	100%

We have a long-term, risk-controlled investment approach using diversified investment options with minimal exposure to volatile investment options like derivatives. Our Benefit Plan assets are invested in pooled separate accounts administered by the Benefit Plan custodian. The underlying assets in the pooled separate accounts are invested in equity securities, debt securities, and real estate. The pooled separate accounts are valued based upon the fair market value of the underlying investments and are deemed to be Level 2.

We do not intend to make any contributions to the pension plan during 2018 . Based on current data and assumptions, the following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next 10 years :

Year Ended		
2018	$	1,090
2019		1,140
2020		1,240
2021		1,310
2022		1,270
Thereafter		7,800
	$	13,850

Other Post-Retirement Benefits - Medical

Prior to December 31, 2015, we sponsored a post-retirement medical plan to provide health care coverage continuation from the date of retirement to age 65 for qualifying employees. Employees hired before 2006 were generally eligible to participate in the plan after five years of service and reaching the age of 55 and would have paid 20% of the monthly insurance premium. Employees hired after 2006 were generally eligible to participate in the plan after five years of service and reaching the age of 55 and were required to pay 100% of the monthly insurance premium; however, after 10 years of service, they were only required to pay 50% of the monthly insurance premium.

On December 31, 2015, we terminated our post-retirement medical plan and extinguished the remaining benefit obligation of $6.6 million . The plan termination gain of $5.6 million is included as a reduction of Operating expense (excluding depreciation) on our consolidated statement of operations for the year ended December 31, 2015.

The changes in the benefit obligation of our post-retirement medical plan as of and for the year ended December 31, 2015 were as follows (in thousands):

	Year Ended December 31, 2015	
Benefit obligation at the beginning of year	$	5,414
Service cost		370
Interest cost		212
Plan amendments		—
Plan termination		(6,632)
Actuarial loss (gain)		636
Projected benefit obligation at end of year	$	—

The post-retirement medical plan was an unfunded plan and therefore had no plan assets as of or during the year ended December 31, 2015.

The weighted-average discount rate used to determine net periodic benefit costs for the year ended December 31, 2015 was 3.5% .

Note 17—Income (Loss) Per Share

Basic income (loss) per share is computed by dividing net income (loss) attributable to common stockholders by the sum of the weighted-average number of common shares outstanding and the weighted-average number of shares issuable under the common stock warrants, representing 354 thousand shares, 347 thousand shares, and 344 thousand shares for the years ended December 31, 2017 , 2016 , and 2015 , respectively. The common stock warrants are included in the calculation of basic income (loss) per share because they are issuable for minimal consideration. The following table sets forth the computation of basic and diluted loss per share (in thousands, except per share amounts):

	Year Ended December 31,		
	2017	2016	2015
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Less: Undistributed income allocated to participating securities (1)	878	—	—
Net income (loss) attributable to common stockholders	71,743	(45,835)	(39,911)
Plus: Net income effect of convertible securities	—	—	—
Numerator for diluted income (loss) per common share	$ 71,743	$ (45,835)	$ (39,911)
Basic weighted-average common stock shares outstanding	45,543	42,349	37,678
Add dilutive effects of common stock equivalents (2)	40	—	—
Diluted weighted-average common stock shares outstanding	45,583	42,349	37,678
Basic income (loss) per common share	$ 1.58	$ (1.08)	$ (1.06)
Diluted income (loss) per common share	$ 1.57	$ (1.08)	$ (1.06)

(1) Participating securities includes restricted stock that has been issued but has not yet vested.

(2) Entities with a net loss from continuing operations are prohibited from including potential common shares in the computation of diluted per share amounts. We have utilized the basic shares outstanding to calculate both basic and diluted loss per share for the years ended December 31, 2016 and 2015 .

For the year ended December 31, 2017 , our calculation of dilutive shares outstanding excluded 65 thousand shares of unvested restricted stock, 1.3 million stock options, and 6.4 million outstanding common stock equivalents assuming our 5.00% Convertible Senior Notes had been converted on the date of issuance. For the year ended December 31, 2016 , our calculation of dilutive shares outstanding excluded 451 thousand shares of unvested restricted stock, 1.3 million stock options, and 6.4 million outstanding common stock equivalents assuming our 5.00% Convertible Senior Notes had been converted on the date of issuance. For the year ended December 31, 2015 , our calculation of dilutive shares outstanding excluded 535 thousand shares of unvested restricted stock and 632 thousand stock options.

As discussed in Note 11—Debt , we have the option of settling the 5.00% Convertible Senior Notes issued in June 2016 in cash or shares of common stock, or any combination thereof, upon conversion. For the year ended December 31, 2017 , diluted income (loss) per share was determined using the if-converted method. We have a net loss for the year ended December 31, 2016 ; therefore, there is no impact for the conversion of the 5.00% Convertible Senior Notes on diluted EPS as the effect would be anti-dilutive.

Note 18—Income Taxes

We have approximately $1.6 billion in net operating loss carryforwards (“NOL carryforwards”); however, we currently have a valuation allowance against this and substantially all of our other deferred taxed assets. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future results of operations, and tax planning strategies in making this assessment. Based upon the level of historical taxable income, significant book losses during the prior periods, and projections for future results of operations over the periods in which the deferred tax assets are deductible, among other factors, management concluded that we did not meet the "more likely than not" requirement in order to recognize deferred tax assets and therefore, a valuation allowance has been recorded for substantially all of our net deferred tax assets at December 31, 2017 and 2016 .

In connection with our emergence from bankruptcy on August 31, 2012, we experienced an ownership change as defined under Section 382 of the Code. Section 382 generally places a limit on the amount of NOL carryforwards and other tax attributes arising before an ownership change that may be used to offset taxable income after an ownership change. We believe that we have qualified for an exception to the general limitation rules. This exception under Code Section 382(l)(5) provides for substantially less restrictive limitations on our NOL carryforwards; however, the NOL carryforwards would have been eliminated if we had experienced another ownership change within the two year period following our Bankruptcy. Our amended and restated certificate of incorporation places restrictions upon the ability of certain equity interest holders to transfer their ownership interest in us. These restrictions are designed to provide us with the maximum assurance that another ownership change does not occur that could adversely impact our NOL carryforwards.

During the years ended December 31, 2017 , 2016 , and 2015 , no adjustments were recognized for uncertain tax benefits.

Our net taxable income must be apportioned to various states based upon the income tax laws of the states in which we derive our revenue. Our NOL carryforwards will not always be available to offset taxable income apportioned to the various states.

On December 22, 2017, the Tax Cuts and Jobs Act ("U.S. tax reform") was signed into law. U.S. tax reform lowered the Federal corporate tax rate from 35% to 21% and made numerous other tax law changes. GAAP requires companies to recognize the effect of tax law changes in the period of enactment. As a result of the change in rate, we remeasured our net deferred tax assets and the associated valuation allowance by $207.7 million . We also released $0.8 million of valuation allowance related to Alternative Minimum Tax ("AMT") credit carried forward from prior years that became refundable in connection with the U.S. tax reform. The current year AMT credit of $0.8 million was also recorded as a long-term receivable rather than a deferred tax asset.

During 2016, we recorded a benefit for the release of $8.6 million of our valuation allowance to offset future temporary differences associated with the 5.00% Convertible Senior Notes . During 2015, we recorded a benefit for the release of $16.8 million of our valuation allowance as we expect to be able to utilize a portion of our NOL carryforwards to offset future taxable income of Mid Pac.

During 2018 and thereafter, we will continue to assess the realizability of our deferred tax assets based on consideration of actual and projected operating results and tax planning strategies. Should actual operating results improve, the amount of the deferred tax asset considered more likely than not to be realizable could be increased.

Income (loss) before income taxes related to our foreign operations was a loss of $1.4 million , and $0.9 million for the years ended December 31, 2016 and 2015 , respectively. We had no income (loss) from foreign operations for the year ended December 31, 2017 .

Income tax expense (benefit) consisted of the following (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Current:			
U.S.—Federal	$ —	$ —	$ —
U.S.—State	2	23	—
Foreign	—	—	(299)
Deferred:			
U.S.—Federal	(1,321)	(7,046)	(14,685)
U.S.—State	—	(889)	(1,804)
Foreign	—	—	—
Total	$ (1,319)	$ (7,912)	$ (16,788)

Income tax expense was different from the amounts computed by applying U.S. Federal income tax rate of 35% to pretax income as a result of the following:

	Year Ended December 31,		
	2017	**2016**	**2015**
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income taxes, net of federal benefit	— %	1.6 %	3.2 %
Expiration of capital loss carryover	— %	(17.6)%	(25.5)%
Change in valuation allowance related to current activity	(30.1)%	9.2 %	25.3 %
Change in valuation allowance related to change in tax rate	(291.2)%	— %	— %
Change in tax rate	291.2 %	— %	— %
Permanent items	1.1 %	(5.7)%	(7.6)%
Provision to return adjustments and other	(7.9)%	(7.8)%	(0.8)%
Actual income tax rate	(1.9)%	14.7 %	29.6 %

Deferred tax assets (liabilities) are comprised of the following (in thousands):

	December 31,	
	2017	**2016**
Deferred tax assets:		
Net operating loss	$ 388,317	$ 611,631
Property and equipment	9,862	23,203
Other	10,263	10,868
Total deferred tax assets	408,442	645,702
Valuation allowance	(383,253)	(613,866)
Net deferred tax assets	25,189	31,836
Deferred tax liabilities:		
Investment in Laramie Energy	18,140	20,600
Convertible notes	3,193	6,866
Intangible assets	3,978	2,671
Other	863	2,337
Total deferred tax liabilities	26,174	32,474
Total deferred tax liability, net	$ (985)	$ (638)

We have NOL carryforwards as of December 31, 2017 of $1.6 billion for federal income tax purposes. If not utilized, the NOL carryforwards will expire during 2027 through 2036 . As noted above, we also have AMT Credit Carryovers of $1.6 million which are refundable under the U.S. tax reform legislation effective tax year 2018.

During 2016, we amended our federal income tax returns for 2012, 2013, and 2014 to properly reflect amortization deductions with respect to certain development costs related to our investment in Laramie Energy that should have been claimed in those years. The impact of the corrected returns was an increase to the deferred tax asset related to our net operating loss and a corresponding decrease in the deferred tax asset related to our investment in Laramie Energy of approximately $59 million .

Note 19—Segment Information

We report the results for the following four business segments: (i) Refining , (ii) Retail , (iii) Logistics , and (iv) Corporate and Other. Beginning in the third quarter of 2016, the results of operations of Wyoming Refining are included in our refining and logistics segments.

We have recast the segment information for the years ended December 31, 2016 and 2015 to reflect the elimination of the Texadian segment as a reportable segment beginning in the first quarter of 2017. As of December 31, 2017, Texadian had ceased its business operations other than the disposal of certain assets and liquidation of inventory. Our Corporate and Other reportable segment now includes administrative costs, our Texadian operations, and several small non-operated oil and gas interests that were owned by our predecessor.

Summarized financial information concerning reportable segments consists of the following (in thousands):

For the year ended December 31, 2017	Refining	Logistics	Retail	Corporate, Eliminations, and Other (1)	Total
Revenues	$ 2,319,638	$ 121,470	$ 326,076	$ (324,118)	$ 2,443,066
Cost of revenues (excluding depreciation)	2,062,804	66,301	249,097	(323,575)	2,054,627
Operating expense (excluding depreciation)	141,068	15,010	45,941	—	202,019
Depreciation, depletion, and amortization	29,753	6,166	6,338	3,732	45,989
General and administrative expense (excluding depreciation)	—	—	—	46,078	46,078
Acquisition and integration costs	—	—	—	395	395
Operating income (loss)	$ 86,013	$ 33,993	$ 24,700	$ (50,748)	$ 93,958
Interest expense and financing costs, net					(31,632)
Loss on termination of financing agreements					(8,633)
Other income, net					914
Change in value of common stock warrants					(1,674)
Equity earnings from Laramie Energy, LLC					18,369
Income before income taxes					71,302
Income tax benefit					1,319
Net income					$ 72,621
Total assets	$ 949,588	$ 118,304	$ 128,966	$ 150,549	$ 1,347,407
Goodwill	53,264	37,373	16,550	—	107,187
Capital expenditures	10,433	8,836	7,073	5,366	31,708

(1) Includes eliminations of intersegment revenues and cost of revenues of $325.2 million for the year ended December 31, 2017 .

For the year ended December 31, 2016	Refining	Logistics	Retail	Corporate, Eliminations, and Other (1)	Total
Revenues	$ 1,702,463	$ 102,779	$ 290,402	$ (230,599)	$ 1,865,045
Cost of revenues (excluding depreciation)	1,580,014	65,439	220,545	(229,659)	1,636,339
Operating expense (excluding depreciation)	112,724	11,239	41,291	962	166,216
Depreciation, depletion, and amortization	17,565	4,679	6,372	3,001	31,617
General and administrative expense (excluding depreciation)	—	—	—	42,073	42,073
Acquisition and integration costs	—	—	—	5,294	5,294
Operating income (loss)	$ (7,840)	$ 21,422	$ 22,194	$ (52,270)	$ (16,494)
Interest expense and financing costs, net					(28,506)
Other expense, net					(98)
Change in value of common stock warrants					2,962
Change in value of contingent consideration					10,770
Equity losses from Laramie Energy, LLC					(22,381)
Loss before income taxes					(53,747)
Income tax benefit					7,912
Net loss					$ (45,835)
Total assets	$ 772,438	$ 120,443	$ 122,570	$ 129,982	$ 1,145,433
Goodwill	53,037	36,145	16,550	—	105,732
Capital expenditures	15,106	1,344	4,375	4,008	24,833

(1) Includes eliminations of intersegment revenues and cost of revenues of $271.9 million for the year ended December 31, 2016 .

For the year ended December 31, 2015	Refining	Logistics	Retail	Corporate, Eliminations, and Other (1)	Total
Revenues	$ 1,895,662	$ 82,671	$ 283,507	$ (195,503)	$ 2,066,337
Cost of revenues (excluding depreciation)	1,718,729	48,660	215,194	(195,215)	1,787,368
Operating expense (excluding depreciation)	95,588	5,433	35,317	5,283	141,621
Depreciation, depletion, and amortization	9,522	3,117	5,421	1,858	19,918
Impairment expense	—	—	—	9,639	9,639
General and administrative expense (excluding depreciation)	—	—	—	44,271	44,271
Acquisition and integration costs	—	—	—	2,006	2,006
Operating income (loss)	$ 71,823	$ 25,461	$ 27,575	$ (63,345)	$ 61,514
Interest expense and financing costs, net					(20,156)
Loss on termination of financing agreements					(19,669)
Other expense, net					(291)
Change in value of common stock warrants					(3,664)
Change in value of contingent consideration					(18,450)
Equity losses from Laramie Energy, LLC					(55,983)
Loss before income taxes					(56,699)
Income tax benefit					16,788
Net loss					$ (39,911)
Total assets	$ 516,482	$ 53,158	$ 115,544	$ 207,077	$ 892,261
Goodwill	13,765	11,012	16,550	—	41,327
Capital expenditures	8,573	6,089	3,643	4,040	22,345

(1) Includes eliminations of intersegment revenues and cost of revenues of $330.0 million for the year ended December 31, 2015 .

Note 20—Related Party Transactions

Term Loan

Certain of our stockholders, or affiliates of our stockholders, were the lenders under our Term Loan. In previous years, they received common stock warrants exercisable for shares of common stock in connection with the origination of the Term Loan. On June 15, 2016 , the Term Loan was amended to permit (i) the issuance of the 5.00% Convertible Senior Notes , (ii) the issuance of the Bridge Notes, and (iii) the WRC Acquisition . We paid a consent fee of $2.5 million in connection with this amendment, $1.3 million of which was paid to an affiliate of Whitebox, one of our largest stockholders. On June 21, 2016 , we repaid $5 million of the Term Loan pursuant to the terms of the amendment, $3.3 million of which was allocated to an affiliate of Whitebox.

On June 30, 2017, we fully repaid and terminated the Term Loan.

Convertible Notes Offering

In June 2016, we issued $115 million in aggregate principal amount of our 5.00% Convertible Senior Notes in a private placement under Rule 144A in the Notes Offering. Please read Note 11—Debt for further discussion.

Prior to the Notes Offering, we also entered into a backstop convertible note commitment letter with funds managed by Highbridge Capital Management, LLC (“Highbridge”) and funds managed on behalf of Whitebox (collectively, the “Backstop Convertible Note Purchasers”), pursuant to which the Backstop Convertible Note Purchasers committed to purchase $100 million aggregate principal amount of senior unsecured convertible notes due 2021, which would be issued in a private offering pursuant to an exemption from the registration requirements of the Securities Act.

The obligations of the Backstop Convertible Note Purchasers to purchase convertible notes automatically terminated upon the consummation of the Notes Offering, provided that each of the Back Up Convertible Note Purchasers and their respective affiliates were allocated the opportunity to purchase at least $32.5 million of the 5.00% Convertible Senior Notes offered in the Notes Offering.

Affiliates of Whitebox and Highbridge purchased an aggregate of $47.5 million and $40.4 million , respectively, principal amount of the 5.00% Convertible Senior Notes in the Notes Offering.

Equity Group Investments ("EGI") - Service Agreement

On September 17, 2013, we entered into a letter agreement ("Services Agreement") with EGI, an affiliate of Zell Credit Opportunities Fund, LP ("ZCOF"), which own 10% or more of our common stock directly or through affiliates. Pursuant to the Services Agreement, EGI agreed to provide us with ongoing strategic, advisory, and consulting services that may include (i) advice on financing structures and our relationship with lenders and bankers, (ii) advice regarding public and private offerings of debt and equity securities, (iii) advice regarding asset dispositions, acquisitions, or other asset management strategies, (iv) advice regarding potential business acquisitions, dispositions, or combinations involving us or our affiliates, or (v) such other advice directly related or ancillary to the above strategic, advisory, and consulting services as may be reasonably requested by us.

EGI does not receive a fee for the provision of the strategic, advisory, or consulting services set forth in the Services Agreement, but may be periodically reimbursed by us, upon request, for (i) travel and out-of-pocket expenses, provided that in the event that such expenses exceed $50 thousand in the aggregate with respect to any single proposed matter, EGI will obtain our consent prior to incurring additional costs, and (ii) provided that we provide prior consent to their engagement with respect to any particular proposed matter, all reasonable fees and disbursements of counsel, accountants, and other professionals incurred in connection with EGI's services under the Services Agreement. In consideration of the services provided by EGI under the Services Agreement, we agreed to indemnify EGI for certain losses relating to or arising out of the Services Agreement or the services provided thereunder.

The Services Agreement has a term of one year and will be automatically extended for successive one -year periods unless terminated by either party at least 60 days prior to any extension date. There were no significant costs incurred related to this agreement during the years ended December 31, 2017 , 2016 , or 2015 .

Bridge Notes Commitment and Issuance

On June 14, 2016 , we entered into a Bridge Notes commitment letter (the "Bridge Notes Commitment Letter") with entities affiliated with EGI and Highbridge pursuant to which such parties committed to purchase an aggregate of up to $52.6 million of Bridge Notes. We paid a fee, in the amount of 5.0% of their respective commitments, to each of the entities affiliated with EGI and Highbridge who had committed to purchasing Bridge Notes pursuant to the Bridge Notes Commitment Letter. This fee was deducted from the proceeds received at the Bridge Notes closing in July 2016. On September 22, 2016 , we repaid $49 million of the outstanding interest and principal on the Bridge Notes and converted the remaining outstanding principal amount on the Bridge Notes into 272,733 shares of our common stock.

Note 21—Subsequent Events

On January 9, 2018, we entered into an Asset Purchase Agreement with CHS, Inc. to acquire twenty one (21) owned retail gasoline, convenience store facilities and twelve (12) leased retail gasoline, convenience store facilities, all at various locations in Washington and Idaho for cash consideration of approximately $70 million plus the agreed value of inventory at closing (the " CHS Acquisition "). The closing of the CHS Acquisition is subject to certain customary closing conditions and is expected to close in the first quarter of 2018. As part of the CHS Acquisition , Par and CHS Inc. will enter into a multi-year branded petroleum marketing agreement for the continued supply of Cenex-branded refined products to the acquired convenience stores. In addition, the parties also will enter into a multi-year supply agreement pursuant to which Par will supply refined products to CHS Inc. within the Rocky Mountain and Pacific Northwest markets.

On February 27, 2018, the Bankruptcy Court entered its final decree closing the Chapter 11 bankruptcy cases of Delta and the other Debtors, discharging the Recovery Trustee, and finding that all assets of the General Trust were resolved, abandoned, or liquidated and have been distributed in accordance with the requirements of the Plan. In addition, the final decree required the Company or the General Trust, as applicable, to maintain the current reserves owed on account of the remaining claims of the U.S. Government and Noble Energy, Inc.

On February 28, 2018 , Laramie Energy closed on a purchase and contribution agreement with an unaffiliated third party that contributed all of its oil and gas properties located in the Piceance Basin and a $23.5 million cash payment, collectively with a fair market value of $28.1 million , into Laramie Energy in exchange for 70,227 of Laramie Energy's newly issued Class A Units. As a result of this transaction, our ownership interest in Laramie Energy decreased from 42.3% to 39.14% .

Note 22—Quarterly Financial Data (Unaudited)

Summarized quarterly data for the years ended December 31, 2017 and 2016 consist of the following (in thousands, except per share amounts):

	Year Ended December 31, 2017			
	Q1	Q2	Q3	Q4
Revenues	$ 605,253	$ 564,245	$ 610,506	$ 663,062
Operating income (loss)	29,189	16,451	26,716	21,602
Net income (loss)	27,786	7,006	18,824	19,005
Net income (loss) per share				
Basic	$ 0.60	$ 0.15	$ 0.41	$ 0.41
Diluted	$ 0.58	$ 0.15	$ 0.41	$ 0.41

	Year Ended December 31, 2016			
	Q1	Q2	Q3	Q4
Revenues	$ 377,812	$ 413,793	$ 510,305	$ 563,136
Operating income (loss)	(19,719)	(3,313)	(21,784)	28,325
Net income (loss)	(18,673)	(13,088)	(27,761)	13,687
Net income (loss) per share				
Basic	$ (0.46)	$ (0.32)	$ (0.67)	$ 0.30
Diluted	$ (0.46)	$ (0.32)	$ (0.67)	$ 0.30

Note 23—Supplemental Oil and Gas Disclosures (Unaudited)

Capitalized costs related to oil and gas activities are as follows (in thousands):

	December 31,	
	2017	2016
Company:		
Unproved properties	$ —	$ —
Proved properties	400	1,122
	400	1,122
Accumulated depreciation and depletion	(275)	(930)
Total	$ 125	$ 192
Company's share of Laramie Energy:		
Unproved properties	$ 13,728	$ 14,416
Proved properties	382,789	334,085
	396,517	348,501
Accumulated depreciation, depletion, and amortization	(111,119)	(91,454)
Total	$ 285,398	$ 257,047

Costs incurred in oil and gas activities including costs associated with assets retirement obligations, are as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Company:			
Development costs—other	$ —	$ —	$ —
Total	$ —	$ —	$ —
Company's share of Laramie Energy:			
Acquisition costs	$ —	$ 65,324	$ —
Development costs—other	49,273	12,805	21,747
Total	$ 49,273	$ 78,129	$ 21,747

For the years ended December 31, 2017 , 2016 , and 2015 , neither we nor Laramie Energy incurred exploratory well costs so no amounts were capitalized or expensed during these respective periods. Accordingly, there were no suspended exploratory well costs at December 31, 2017 , 2016 , and 2015 that were being evaluated.

A summary of the results of operations for oil and gas producing activities, excluding general and administrative costs, is as follows (in thousands):

	Year Ended December 31,		
	2017	2016	2015
Company:			
Revenue			
Oil and gas revenues	$ 288	$ 190	$ 2,019
Expenses			
Production costs	29	147	5,283
Depletion and amortization	66	69	42
Exploration	—	—	—
Abandoned and impaired properties	—	—	—
Results of operations of oil and gas producing activities	$ 193	$ (26)	$ (3,306)
Company's share of Laramie Energy:			
Revenue			
Oil and gas revenues	$ 66,783	$ 43,607	$ 14,217
Expenses			
Production costs	32,606	27,750	11,047
Impairment of unproved properties	—	—	3,977
Depletion, depreciation, and amortization	21,277	17,534	8,226
Results of operations of oil and gas producing activities	$ 12,900	$ (1,677)	$ (9,033)
Total results of operations of oil and gas producing activities	$ 13,093	$ (1,703)	$ (12,339)

Oil and Gas Reserve Information

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve 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 estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

Estimates of our crude oil and natural gas reserves and present values as of December 31, 2017 , 2016 , and 2015 , were prepared by Netherland, Sewell & Associates, Inc., independent reserve engineers.

A summary of changes in estimated quantities of proved reserves for the years ended December 31, 2017 , 2016 , and 2015 is as follows:

	Gas (MMcf)	Oil (Mbbl)	NGLS (Mbbl)	Total (MMcfe) (1)
Company:				
Balance at January 1, 2015	601	77	17	1,165
Revisions of quantity estimate	(330)	(35)	(15)	(630)
Extensions and discoveries	—	—	—	—
Production	(83)	(36)	(2)	(311)
Balance at December 31, 2015 (2)	188	6	—	224
Revisions of quantity estimate	196	3	8	262
Extensions and discoveries	—	—	—	—
Production	(54)	(2)	—	(66)
Balance at December 31, 2016 (3)	330	7	8	420
Revisions of quantity estimate	109	2	3	139
Extensions and discoveries	—	—	—	—
Production	(47)	(2)	—	(59)
Balance at December 31, 2017 (4)	392	7	11	500
Company's share of Laramie Energy:				
Balance at January 1, 2015, as revised (5)	192,015	684	5,444	228,788
Revisions of quantity estimate	(86,092)	(295)	(2,281)	(101,553)
Extensions and discoveries	32,041	131	1,007	38,869
Acquisitions and divestures	(5,945)	(20)	(171)	(7,091)
Production	(4,745)	(20)	(149)	(5,759)
Balance at December 31, 2015, as revised (2) (5)	127,274	480	3,850	153,254
Revisions of quantity estimate	28,195	53	526	31,672
Extensions and discoveries	638	1	19	758
Acquisitions and divestures	168,887	492	4,701	200,045
Production	(15,192)	(59)	(552)	(18,858)
Balance at December 31, 2016, as revised (3) (5)	309,802	967	8,544	366,871
Revisions of quantity estimate	1,344	211	(434)	3
Extensions and discoveries (4)	—	—	—	—
Acquisitions and divestures	—	—	—	—
Production	(18,104)	(71)	(608)	(22,178)
Balance at December 31, 2017 (4)	293,042	1,107	7,502	344,696
Total at December 31, 2017	293,434	1,114	7,513	345,196

(1) MMcfe is based on a ratio of 6 Mcf to 1 barrel.

(2) During 2015 , the Company's estimated proved reserves, inclusive of the Company's share of Laramie Energy's estimated proved reserves, decreased by 76,475 MMcfe or approximately 33% . Revisions of quantity estimates related to our share of Laramie Energy's estimated proved reserves resulted in a decrease of 101,553 MMcfe from the beginning of year reserves. These revisions of quantity estimate are primarily associated with wells becoming uneconomic during 2015.

(3) During 2016 , the Company's estimated proved reserves, inclusive of the Company's share of Laramie Energy's estimated proved reserves, increased by 213,813 MMcfe or approximately 139% . Acquisitions and divestitures related to our share of Laramie Energy's estimated proved reserves resulted in an increase of 200,045 MMcfe from the beginning of year reserves. This increase was primarily due to Laramie Energy's acquisition of properties in the Piceance Basin for $152.1 million in March 2016 . Please read Note 3—Investment in Laramie Energy, LLC for more information. The increase of 31,672 MMcfe

in Revisions of quantity estimate related to our share of Laramie Energy's estimated proved reserves is primarily due to wells that became economic as a result of increased operator efficiency and cost reductions.

(4) During 2017 , the Company's estimated proved reserves, inclusive of the Company's share of Laramie Energy's estimated proved reserves, decreased by 22,095 MMcfe or approximately 6% . Production volumes related to our share of Laramie Energy's estimated proved reserves resulted in a decrease of 22,178 MMcfe. Beginning in 2017, Par has decided to base its determination of Laramie Energy proved undeveloped reserves on only a two year drilling and three year completion time horizon, which has resulted in negative revisions to our proved reserves of 17,216 MMcfe during 2017. The Company's share of Laramie Energy's revisions of quantity estimate also includes 30,362 MMcfe of positive revisions associated with 44 probable locations that were converted to proved developed reserves during 2017. These 44 locations converted to proved reserves during 2017 were not considered extensions because they were drilled in proved areas that are slightly offset to other proved locations. The remaining decrease in estimated proved reserves was due to performance and other changes to the Company's share of Laramie Energy's proved developed producing and developed non-producing reserves.

(5) We have revised our previously disclosed proved reserves quantities as of December 31, 2016, 2015, and 2014 to remove certain proved undeveloped locations scheduled for completion more than 5 years from initial booking that were classified as proved undeveloped reserves as of December 31, 2016, 2015, and 2014. Par’s share of Laramie Energy's proved undeveloped reserves from the removed proved undeveloped locations was 19,307 MMcfe, 7,587 MMcfe, and 23,786 MMcfe, representing 5% , 5% , and 9% of total proved reserves as of December 31, 2016, 2015, and 2014, respectively. These prior period revisions are not material to our consolidated financial statements for the respective periods.

	Gas (MMcf)	Oil (Mbbl)	NGLS (Mbbl)	Total (MMcfe) (1)
December 31, 2015				
Proved developed reserves				
Company	188	6	—	224
Company's share of Laramie Energy	65,499	248	1,931	78,573
Total	65,687	254	1,931	78,797
Proved undeveloped reserves				
Company	—	—	—	—
Company's share of Laramie Energy (2)	61,775	232	1,919	74,681
Total	61,775	232	1,919	74,681
December 31, 2016				
Proved developed reserves				
Company	330	7	8	420
Company's share of Laramie Energy	159,500	516	4,349	188,690
Total	159,830	523	4,357	189,110
Proved undeveloped reserves				
Company	—	—	—	—
Company's share of Laramie Energy (2)	150,302	451	4,195	178,181
Total	150,302	451	4,195	178,181
December 31, 2017				
Proved developed reserves				
Company	392	7	11	500
Company's share of Laramie Energy	174,464	658	4,589	205,946
Total	174,856	665	4,600	206,446
Proved undeveloped reserves				
Company	—	—	—	—
Company's share of Laramie Energy	118,578	449	2,913	138,750
Total	118,578	449	2,913	138,750

(1) MMcfe is based on a ratio of 6 Mcf to 1 barrel.

(2) We have revised our previously disclosed proved undeveloped reserves quantities as of December 31, 2016 and 2015 to remove certain proved undeveloped locations scheduled for completion more than 5 years from initial booking that were classified as proved undeveloped reserves as of December 31, 2016 and 2015. Par's share of Laramie Energy's proved undeveloped reserves from the removed proved undeveloped locations was 19,307 MMcfe and 7,587 MMcfe as of December 31, 2016 and 2015, respectively. These prior period revisions are not material to our consolidated financial statements for the respective periods.

	Price per MMbtu (2)	WTI per Bbl
Base pricing, before adjustments for contractual differentials (Company and Laramie Energy): (1)		
December 31, 2015	$ 2.39	$ 50.28
December 31, 2016	2.29	42.75
December 31, 2017	2.68	51.34

(1) Proved reserves are required to be calculated based on the 12-month, first day of the month historical average price in accordance with SEC rules. The prices shown above are base index prices to which adjustments are made for contractual deducts and other factors.

(2) The CIG index was used for pricing during 2015. In 2017 and 2016 , pricing is based on the Northwest spot price index.

Future net cash flows presented below are computed using applicable prices (as summarized above) and costs and are net of all overriding royalty revenue interests.

	December 31,		
	2017	2016	2015
	(in thousands)		
Company:			
Future net cash flows	$ 1,802	$ 1,154	$ 690
Future costs			
Production	902	713	345
Development and abandonment	—	2	25
Income taxes (1)	—	—	—
Future net cash flows	900	439	320
10% discount factor	(328)	(154)	(128)
Discounted future net cash flows	$ 572	$ 285	$ 192
Company's share of Laramie Energy: (2)			
Future net cash flows	$ 1,026,005	$ 905,607	$ 405,365
Future costs			
Production	491,748	462,684	238,129
Development and abandonment	109,248	136,224	67,443
Income taxes (1)	—	—	—
Future net cash flows	425,009	306,699	99,793
10% discount factor	(209,188)	(165,557)	(60,188)
Discounted future net cash flows	$ 215,821	$ 141,142	$ 39,605
Total discounted future net cash flows	$ 216,393	$ 141,427	$ 39,797

(1) No income tax provision is included in the standardized measure of discounted future net cash flows calculation shown above as we do not project to be taxable or pay cash income taxes based on its available tax assets and additional tax assets generated in the development of its reserves because the tax basis of its oil and gas properties and NOL carryforwards exceeds the amount of discounted future net earnings.

(2) We have revised our previously disclosed discounted future net cash flows as of December 31, 2016 and 2015 to reflect the removal of Laramie Energy's proved undeveloped locations scheduled for completion more than 5 years from initial booking that were classified as proved undeveloped reserves as of December 31, 2016 and 2015. Par's share of Laramie Energy's discounted future net cash flows from the removed locations was $1.8 million and $0.4 million , representing 1% and 1%

of total discounted future net cash flows as of December 31, 2016 and 2015, respectively. These prior period revisions are not material to our consolidated financial statements for the respective periods.

The principal sources of changes in the standardized measure of discounted net cash flows for the years ended December 31, 2017 , 2016 , and 2015 are as follows (in thousands):

	Company	Company's Share of Laramie Energy	Total
Balance at January 1, 2015 (1)	$ 1,766	$ 160,671	$ 162,437
Sales of oil and gas production during the period, net of production costs	(479)	(5,753)	(6,232)
Acquisitions and divestitures	—	(4,789)	(4,789)
Net change in prices and production costs	(679)	(153,564)	(154,243)
Changes in estimated future development costs	8	788	796
Extensions, discoveries, and improved recovery	—	9,273	9,273
Revisions of previous quantity estimates, estimated timing of development and other	(601)	911	310
Previously estimated development and abandonment costs incurred during the period	—	15,008	15,008
Accretion of discount	177	17,060	17,237
Balance at December 31, 2015 (1)	192	39,605	39,797
Sales of oil and gas production during the period, net of production costs	(62)	(7,979)	(8,041)
Acquisitions and divestitures	—	81,066	81,066
Net change in prices and production costs	(20)	2,994	2,974
Changes in estimated future development costs	14	(8,575)	(8,561)
Extensions, discoveries, and improved recovery	—	231	231
Revisions of previous quantity estimates, estimated timing of development and other	142	16,995	17,137
Previously estimated development and abandonment costs incurred during the period	—	12,805	12,805
Accretion of discount	19	4,000	4,019
Balance at December 31, 2016 (1)	285	141,142	141,427
Sales of oil and gas production during the period, net of production costs	(28)	(29,911)	(29,939)
Net change in prices and production costs	(60)	35,597	35,537
Revisions of previous quantity estimates, estimated timing of development and other	346	37,692	38,038
Previously estimated development and abandonment costs incurred during the period	—	17,187	17,187
Accretion of discount	29	14,114	14,143
Balance at December 31, 2017	$ 572	$ 215,821	$ 216,393

(1) We have revised our previously disclosed discounted future net cash flows as of December 31, 2016, 2015, and 2014 to reflect the removal of Laramie Energy's proved undeveloped locations scheduled for completion more than 5 years from initial booking that were classified as proved undeveloped reserves as of December 31, 2016, 2015, and 2014. Par's share of Laramie Energy's discounted future net cash flows from the removed locations was $1.8 million , $0.4 million , and $9.9 million , representing 1% , 1% , and 6% of total discounted future net cash flows as of December 31, 2016, 2015, and 2014, respectively. These prior period revisions are not material to our consolidated financial statements for the respective periods.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
PAR PACIFIC HOLDINGS, INC. (PARENT ONLY)
BALANCE SHEETS
(in thousands, except share amounts)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 65,615	$ 10,361
Restricted cash	744	746
Prepaid and other current assets	11,768	9,200
Due from subsidiaries	8,113	66,900
Total current assets	86,240	87,207
Property and equipment		
Property, plant, and equipment	15,773	10,259
Less accumulated depreciation and depletion	(6,226)	(3,485)
Property and equipment, net	9,547	6,774
Long-term assets		
Investment in subsidiaries	552,748	513,693
Other long-term assets	1,976	1,976
Total assets	$ 650,511	$ 609,650
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 4,510	$ 4,529
Other accrued liabilities	12,913	8,141
Due to subsidiaries	82,524	73,529
Total current liabilities	99,947	86,199
Long-term liabilities		
Long-term debt	95,486	148,456
Common stock warrants	6,808	5,134
Long-term capital lease obligations	551	952
Total liabilities	202,792	240,741
Stockholders' equity		
Preferred stock, $0.01 par value: 3,000,000 shares authorized, none issued	—	—
Common stock, $0.01 par value; 500,000,000 shares authorized at December 31, 2017 and December 31, 2016, 45,776,087 shares and 45,533,913 shares issued at December 31, 2017 and December 31, 2016, respectively	458	455
Additional paid-in capital	593,295	587,057
Accumulated deficit	(148,178)	(220,799)
Accumulated other comprehensive income	2,144	2,196
Total stockholders' equity	447,719	368,909
Total liabilities and stockholders' equity	$ 650,511	$ 609,650

This statement should be read in conjunction with the notes to consolidated financial statements.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
PAR PACIFIC HOLDINGS, INC. (PARENT ONLY)
STATEMENTS OF OPERATIONS
(in thousands)

	Year Ended December 31,		
	2017	2016	2015
Operating expenses			
Depreciation and amortization	$ 2,871	$ 2,205	$ 963
General and administrative expense (excluding depreciation)	18,922	15,618	16,558
Acquisition and integration expense	192	4,781	1,776
Total operating expenses	21,985	22,604	19,297
Operating loss	(21,985)	(22,604)	(19,297)
Other income (expense)			
Interest expense and financing costs, net	(13,709)	(18,246)	(13,028)
Loss on termination of financing agreements	(1,804)	—	—
Interest income from subsidiaries	—	583	1,000
Other income (expense), net	631	67	215
Change in value of common stock warrants	(1,674)	2,962	(3,664)
Equity in earnings (losses) of subsidiaries	111,162	(17,170)	(5,137)
Total other income (expense), net	94,606	(31,804)	(20,614)
Income (loss) before income taxes	72,621	(54,408)	(39,911)
Income tax benefit	—	8,573	—
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)

This statement should be read in conjunction with the notes to consolidated financial statements.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
PAR PACIFIC HOLDINGS, INC. (PARENT ONLY)
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Other comprehensive income (loss): (1)			
Reclassification of other post-retirement benefits loss to net income	—	—	1,082
Other post-retirement benefits income (loss), net of tax	$ (52)	2,196	(636)
Total other comprehensive income (loss)	(52)	2,196	446
Comprehensive income (loss)	$ 72,569	$ (43,639)	$ (39,465)

(1) Other comprehensive income (loss) relates to benefit plans at our subsidiaries.

This statement should be read in conjunction with the notes to consolidated financial statements.

SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
PAR PACIFIC HOLDINGS, INC. (PARENT ONLY)
STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities:			
Net income (loss)	$ 72,621	$ (45,835)	$ (39,911)
Adjustments to reconcile net loss to cash provided by (used in) operating activities:			
Depreciation and amortization	2,871	2,205	962
Non-cash interest expense	5,617	13,722	6,860
Non-cash interest income from subsidiary	—	(583)	(1,000)
Change in value of common stock warrants	1,674	(2,962)	3,644
Deferred taxes	—	(8,573)	—
Stock-based compensation	7,204	2,226	3,202
Equity in losses (income) of subsidiaries	(111,162)	17,170	5,137
Loss on termination of financing agreements	1,804	—	—
Net changes in operating assets and liabilities:			
Prepaid and other assets	(2,568)	25	(8,466)
Accounts payable and other accrued liabilities	3,088	381	3,674
Net cash used in operating activities	(18,851)	(22,224)	(25,898)
Cash flows from investing activities:			
Investments in subsidiaries	(2,072)	(264,163)	(89,603)
Distributions from subsidiaries	70,645	9,047	68,418
Note receivable from subsidiary	—	10,000	—
Change in restricted cash	2	—	—
Capital expenditures	(5,366)	(4,321)	(4,461)
Due to (from) subsidiaries	80,762	(23,947)	27,627
Net cash provided by (used in) investing activities	143,971	(273,384)	1,981
Cash flows from financing activities:			
Proceeds from sale of common stock, net of offering costs	—	49,044	76,056
Proceeds from borrowings	—	172,282	7,378
Repayments of borrowings	(68,873)	(63,062)	(37,214)
Payment of deferred loan costs	—	(6,298)	(307)
Due to (from) subsidiaries	—	63,578	—
Other financing activities, net	(993)	(598)	(1,087)
Net cash provided by (used in) financing activities	(69,866)	214,946	44,826
Net increase (decrease) in cash and cash equivalents	55,254	(80,662)	20,909
Cash and cash equivalents at beginning of period	10,361	91,023	70,114
Cash and cash equivalents at end of period	$ 65,615	$ 10,361	$ 91,023
Supplemental cash flow information:			
Cash received (paid) for:			
Interest	$ (7,856)	$ (4,557)	$ (4,709)
Taxes	(1,478)	—	51
Non-cash investing and financing activities:			
Accrued capital expenditures	$ 370	$ 361	$ 417
Value of warrants and debt reclassified to equity	—	3,084	7,691
Capital leases	165	1,575	216

This statement should be read in conjunction with the notes to consolidated financial statements.

Item 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange of Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on March 12, 2018 .

PAR PACIFIC HOLDINGS, INC.

By: /s/ William Pate
William Pate
President and Chief Executive Officer

By: /s/ William Monteleone
William Monteleone
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Form 10-K has been signed below by the following persons on our behalf and in the capacities indicated and on March 12, 2018 .

Signature	Title
/s/ WILLIAM PATE William Pate	President and Chief Executive Officer (Principal Executive Officer)
/s/ WILLIAM MONTELEONE William Monteleone	Chief Financial Officer (Principal Financial Officer)
/s/ IVAN GUERRA Ivan Guerra	Chief Accounting Officer (Principal Accounting Officer)
/s/ MELVYN N. KLEIN Melvyn N. Klein	Chairman of the Board of Directors
/s/ ROBERT S. SILBERMAN Robert S. Silberman	Vice Chairman of the Board
/s/ TIMOTHY CLOSSEY Timothy Clossey	Director
/s/ L. MELVIN COOPER L. Melvin Cooper	Director
/s/ CURTIS ANASTASIO Curtis Anastasio	Director
/s/ WALTER A. DODS, JR. Walter A. Dods, Jr.	Director
/s/ JOSEPH ISRAEL Joseph Israel	Director

EXHIBIT 12.1

RATIO OF EARNINGS TO FIXED CHARGES

(in thousands)

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Income (loss) before income taxes	$ 71,302	$ (53,747)	$ (56,699)	$ (47,496)	$ (79,173)
Add back:					
Interest expense and financing costs, net	31,632	28,506	20,156	17,995	13,285
Estimate of interest component of rental expense (1)	13,596	13,052	5,853	9,971	2,046
Equity losses (earnings) from Laramie Energy, LLC	(18,369)	22,381	55,983	(2,849)	2,941
Earnings	$ 98,161	$ 10,192	$ 25,293	$ (22,379)	$ (60,901)
Fixed charges					
Interest expense and financing costs, net	31,632	28,506	20,156	17,995	13,285
Estimate of interest component of rental expense	13,596	13,052	5,853	9,971	2,046
Total fixed charges	$ 45,228	$ 41,558	$ 26,009	$ 27,966	$ 15,331
Ratio of earnings to fixed charges	2.2	NA (2)	NA (2)	NA (2)	NA (2)
Amount by which fixed charges exceed earnings	NA	$ 31,366	$ 716	$ 50,345	$ 76,232

(1) Consists of 33% of rental expense, which we believe to be a reasonable estimate of interest factor in our rental expense.

(2) Earnings were inadequate to cover fixed charges for the respective periods.

Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT

Name	Jurisdiction
EWI, LLC	Delaware
Hermes Consolidated, LLC	Delaware
HEWW Equipment, LLC	Delaware
HIE Retail, LLC	Hawaii
Mid Pac Petroleum, LLC	Delaware
Par Hawaii, Inc.	Hawaii
Par Hawaii Refining, LLC	Hawaii
Par Hawaii Shared Services, LLC	Delaware
Par New Mexico, LLC	Delaware
Par Petroleum, LLC	Delaware
Par Piceance Energy Equity, LLC	Delaware
Par Point Arguello, LLC	Delaware
Par Utah, LLC	Delaware
Par Washington, LLC	Delaware
Par Wyoming, LLC	Delaware
Par Wyoming Holdings, LLC	Delaware
Texadian Energy, Inc.	Delaware
Texadian Energy Canada Limited	Alberta, Canada
Wyoming Pipeline Company, LLC	Wyoming
Laramie Energy, LLC (42.3% interest)	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-185612, 333-208575 and 333-216518 on Form S-8 and Registration Statement Nos. 333-192519, 333-195662, 333-204597, 333-212107, 333-213472, 333-213471 and 333-214593 on Form S-3 of our reports dated March 12, 2018, relating to the consolidated financial statements and financial statement schedule of Par Pacific Holdings, Inc. and subsidiaries and the effectiveness of Par Pacific Holdings, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Par Pacific Holdings, Inc. for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas March 12, 2018

EXHIBIT 23.2

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-185612, 333-208575, and 333-216518 on Form S-8 and Registration Statement Nos. 333-192519, 333-195662, 333-204597, 333-212107, 333-213472, 333-213471, and 333-214593 on Form S-3 of Par Pacific Holdings, Inc. of our report dated March 9, 2018 related to the financial statements of Laramie Energy, LLC as of December 31, 2017 and 2016, and for the three years ended December 31, 2017, appearing in this Annual Report on Form 10-K of Par Pacific Holdings, Inc. for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
March 12, 2018

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.4

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Annual Report on Form 10-K of Par Pacific Holdings, Inc. for the year ended December 31, 2017, of our report dated March 6, 2018, with respect to estimates of reserves and future net revenue of Par Pacific Holdings, Inc. ("Par Pacific"), as of December 31, 2017, and to all references to our firm included in this Annual Report. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and of our reserves report as of December 31, 2017, and references thereto, into Par Pacific's Registration Statement Nos. 333-185612, 333-208575 and 333-216518 on Form S-8 and Registration Statement Nos. 333-192519, 333-195662, 333-204597, 333-212107, 333-213472, 333-213471, and 333-214593.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ G. Lance Binder

G. Lance Binder, P.E.
Executive Vice President

Dallas, Texas
March 12, 2018

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO RULE 13a-14(a)/15d-14(a) PROMULGATED UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, William Pate, certify that:

1. I have reviewed this annual report on Form 10-K of Par Pacific Holdings, Inc.;

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(s) 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(s) 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 12, 2018

/s/ William Pate

William Pate

President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO RULE 13a-14(a)/15d-14(a) PROMULGATED UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, William Monteleone, certify that:

1. I have reviewed this annual report on Form 10-K of Par Pacific Holdings, Inc.;

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(s) 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(s) 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 12, 2018

/s/ William Monteleone

William Monteleone
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Par Pacific Holdings, Inc. (the “Company”) on Form 10-K for the period ended December 31, 2017 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, William Pate, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to my 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 the Company.

/s/ William Pate

William Pate
President and Chief Executive Officer

March 12, 2018

Exhibit 32.2

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Par Pacific Holdings, Inc. (the “Company”) on Form 10-K for the period ended December 31, 2017 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, I, William Monteleone, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that to my 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 the Company.

/s/ William Monteleone

William Monteleone
Chief Financial Officer

March 12, 2018

March 6, 2018

Mr. Will Monteleone
Par Pacific Holdings, Inc.
One Memorial Plaza, Suite 875
800 Gessner Road
Houston, Texas 77024

Dear Mr. Monteleone:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Par Pacific Holdings, Inc. (Par) interest in certain oil and gas properties located in Colorado and New Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Par. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Par's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Par interest in these properties, as of December 31, 2017, to be:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	665.3	4,600.2	174,856.1	264,487.1	158,571.7
Proved Undeveloped	448.8	2,912.5	118,577.5	161,422.2	57,820.8
Total Proved	1,114.1	7,512.7	293,433.6	425,909.4	216,392.5

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of December 31, 2017, there are no proved developed non-producing reserves for these properties. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Par's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Par's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Northwest (Wyoming pool) spot price of $2.682 per MMBTU is adjusted for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $46.06 per barrel of oil, $20.97 per barrel of NGL, and $2.791 per MCF of gas.

Operating costs used in this report are based on operating expense records of Par and of Laramie Energy, LLC (Laramie), the operator of most of the properties. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses of Par are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Laramie and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Laramie's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Par interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Par receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Laramie, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Par, Laramie, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Benjamin W. Johnson, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2007 and has over 2 years of prior industry experience. John G. Hattner, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Benjamin W. Johnson
Benjamin W. Johnson, P.E. 124738
Vice President

By: /s/ John G. Hattner
John G. Hattner, P.G. 559
Senior Vice President

Date Signed: March 6, 2018   Date Signed: March 6, 2018

BWJ:BWY

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir* . Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2) : Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen* . Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate* . Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate* . The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves* . Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project* . A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well* . A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible* . The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)* . Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs* . Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well* . An exploratory well is 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 gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well* . An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field* . An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field

which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i) : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability

that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26) : Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

LARAMIE ENERGY, LLC

Financial Statements
and
Independent Auditors' Report
December 31, 2017,
2016, and 2015

LARAMIE ENERGY, LLC

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INDEPENDENT AUDITORS' REPORT

To the Members of
Laramie Energy, LLC
Denver, Colorado

We have audited the accompanying financial statements of Laramie Energy, LLC (the "Company"), which comprise the balance sheets as of December 31, 2017 and 2016, and the related statements of operations, members' equity, and cash flows for the three years ended December 31, 2017, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Laramie Energy, LLC as of December 31, 2017 and 2016, and the results of its operations and its cash flows for the three years ended December 31, 2017 in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

March 9, 2018

LARAMIE ENERGY, LLC

Balance Sheets

	December 31, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 285,111	$ 190,533
Accounts receivable	14,070,484	10,850,673
Prepaid expenses and other current assets	1,418,237	1,157,973
Derivative instruments	2,983,243	—
Total current assets	18,757,075	12,199,179
Property and equipment		
Oil and gas properties, successful efforts method		
Proved properties	904,939,398	789,799,105
Unproved properties	32,453,628	34,080,358
Real estate and ranch property	40,284,743	40,570,713
Office furniture, equipment, and other	3,867,973	4,763,775
	981,545,742	869,213,951
Less: accumulated depletion, depreciation, and amortization	(262,692,951)	(216,203,690)
Total property and equipment, net	718,852,791	653,010,261
Debt issue costs, net of amortization of $1,845,758 and $1,326,840 at December 31, 2017 and 2016, respectively	1,591,308	1,899,139
Other assets	—	112,830
Total assets	$ 739,201,174	$ 667,221,409
Liabilities and Members' Equity		
Current liabilities		
Accounts payable	$ 14,908,628	$ 6,796,114
Oil and gas sales payable	3,959,226	3,262,715
Accrued liabilities	23,264,364	16,896,732
Derivative instruments	16,811	31,111,555
Total current liabilities	42,149,029	58,067,116
Non-current liabilities		
Notes payable	171,500,000	117,500,000
Redeemable Preferred A units	35,341,697	30,883,755
Derivative instruments	—	12,163,466
Accrued liabilities	3,668,530	2,181,307
Asset retirement obligation	26,986,294	23,902,588
Total non-current liabilities	237,496,521	186,631,116
Total liabilities	279,645,550	244,698,232
Commitments and contingencies (Note 8)		
Members' equity		
Members' equity	546,103,029	539,907,795
Accumulated deficit	(86,547,405)	(117,384,618)
Total members' equity	459,555,624	422,523,177

Total liabilities and members’ equity	$ 739,201,174	$ 667,221,409

See notes to financial statements.

LARAMIE ENERGY, LLC

Statements of Operations

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues			
Natural gas sales	$ 120,448,493	$ 84,073,533	$ 35,374,165
Condensate sales	7,510,195	5,356,238	2,296,011
Natural gas liquids sales	28,774,463	15,395,959	5,199,768
Other revenues	1,146,167	—	—
Total revenues	157,879,318	104,825,730	42,869,944
Operating expenses			
Lease operating expenses	25,773,674	21,687,357	11,348,247
Gathering, transportation and processing	43,584,801	39,104,224	19,438,715
Production and property taxes	5,788,033	4,084,776	859,936
Depletion, depreciation, amortization and accretion	51,586,780	43,736,701	24,988,111
Impairment of unproved properties	—	—	12,272,304
Abandoned property and expired leases	1,936,784	2,080,839	1,733,014
General and administrative	23,190,296	21,456,875	13,213,437
Total operating expenses	151,860,368	132,150,772	83,853,764
Income (loss) from operations	6,018,950	(27,325,042)	(40,983,820)
Other income (expense)			
Gain (loss) on derivative instruments	35,530,531	(27,728,211)	(5,874,529)
Interest expense and other financing costs	(6,458,928)	(4,367,136)	(2,156,197)
Gain (loss) on disposal of assets	50,855	656,777	(1,735)
Surface land operating expense	(327,276)	(154,009)	(167,500)
Preferred dividend	(4,166,112)	(3,193,820)	—
Miscellaneous income	189,193	262,791	24,304
Total other income (expense)	24,818,263	(34,523,608)	(8,175,657)
Net income (loss)	$ 30,837,213	$ (61,848,650)	$ (49,159,477)

See notes to financial statements.

LARAMIE ENERGY, LLC

Statements of Members' Equity
For the Years Ended December 31, 2017, 2016 and 2015

	Class A Units		Class B Units		Accumulated	Total Members'
	Units	Amount	Units	Amount	Deficit	Equity
Balances, January 1, 2015	500,000	$ 365,046,126	—	$ —	$ (6,376,491)	$ 358,669,635
Net contributions of Class A Unitholders	157,612	93,857,615	—	—	—	93,857,615
Class B unit issuance and compensation	—	—	13,025	2,567,408	—	2,567,408
Net loss	—	—	—	—	(49,159,477)	(49,159,477)
Balances, December 31, 2015	657,612	458,903,741	13,025	2,567,408	(55,535,968)	405,935,181
Net contributions of Class A Unitholders	208,522	71,886,073	—	—	—	71,886,073
Class B unit issuance and compensation, net of forfeitures	—	—	1,570	6,550,573	—	6,550,573
Net loss	—	—	—	—	(61,848,650)	(61,848,650)
Balances, December 31, 2016	866,134	530,789,814	14,595	9,117,981	(117,384,618)	422,523,177
Class B unit issuance and compensation, net of forfeitures	—	—	(360)	6,195,234	—	6,195,234
Net income	—	—	—	—	30,837,213	30,837,213
Balances, December 31, 2017	866,134	$ 530,789,814	14,235	$ 15,313,215	$ (86,547,405)	$ 459,555,624

See notes to financial statements.

LARAMIE ENERGY, LLC

Statements of Cash Flows

	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income (loss)	$ 30,837,213	$ (61,848,650)	$ (49,159,477)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization and accretion	51,586,780	43,736,701	24,988,111
Impairment of unproved properties	—	—	12,272,304
Abandoned property and expired leases	1,936,784	2,080,839	1,733,014
Settlement of asset retirement obligation	(667,554)	(141,260)	—
Non-cash interest costs	810,748	432,270	237,167
Share-based compensation expense	6,195,234	6,550,573	2,567,408
Preferred dividend	4,166,112	3,193,820	—
Unrealized (gain) loss on derivative instruments	(46,241,453)	34,452,084	16,623,179
(Gain) loss on disposal of assets	(50,855)	(656,777)	1,735
Changes in operating assets and liabilities			
Accounts receivable	(3,219,811)	(8,321,252)	2,081,855
Prepaid expenses and other assets	(147,434)	(632,888)	59,935
Accounts payable	(2,497,286)	695,129	(418,494)
Oil and gas sales payable	696,511	2,405,983	(1,285,820)
Accrued liabilities	122,771	5,238,846	626,359
Net cash provided by operating activities	43,527,760	27,185,418	10,327,276
Cash flows from investing activities			
Proceeds from sale of fixed assets	919,738	1,187,828	7,386
Deposit on acquisition	—	—	(15,750,000)
Additions to property and equipment	(98,141,833)	(167,435,240)	(62,272,656)
Net cash used in investing activities	(97,222,095)	(166,247,412)	(78,015,270)
Cash flows from financing activities			
Proceeds from notes payable	205,350,000	150,250,000	113,650,000
Payments on notes payable	(151,350,000)	(110,000,000)	(134,400,000)
Debt issue costs	(211,087)	(1,485,493)	(738,775)
Members' contributions	—	100,000,000	89,888,125
Costs of raising capital	—	(423,992)	—
Net cash provided by financing activities	53,788,913	138,340,515	68,399,350
Increase (decrease) in cash and cash equivalents	94,578	(721,479)	711,356
Cash and cash equivalents, beginning of period	190,533	912,012	200,656
Cash and cash equivalents, end of period	$ 285,111	$ 190,533	$ 912,012

(Continued on the following page)

See notes to financial statements.

(Continued from the previous page)

Supplemental disclosure of activity:

Cash paid for interest in 2017, 2016 and 2015 was $5,106,566, $3,651,018 and $1,584,440, respectively.

Supplemental disclosure of non-cash activity:

During the years ended December 31, 2017, 2016 and 2015, the Company recorded an asset retirement cost and related obligation of $2,039,180, $15,587,862 and $1,502,034, respectively.

During the year ended December 31, 2016, the Company recorded a non-cash property addition of $15.75 million from a deposit on acquisition.

During the year ended December 31, 2015 the Company recorded a non-cash property contribution from an equity investor pursuant to an acquisition of $3,969,490.

During the year ended December 31, 2017, sixteen wells were plugged and abandoned and three pads were reclaimed. Asset retirement obligation liabilities of $211,849 were settled and offset abandoned property expenses. In addition, asset retirement costs and related obligation liabilities of $29,515 were written off.

During the year ended December 31, 2016, two wells were plugged and abandoned and one pad was reclaimed. Asset retirement obligation liabilities of $40,631 were settled and offset abandoned property expenses.

Capital expenditures of $11,801,484 and $11,613,368 were unpaid and included in accrued liabilities and accounts payable, respectively, at December 31, 2017. Capital expenditures of $4,069,400 and $1,003,568 were unpaid and included in accrued liabilities and accounts payable, respectively, at December 31, 2016. Capital expenditures of $4,272,400 and $2,699,349 were unpaid and included in accrued liabilities and accounts payable, respectively, at December 31, 2015.

Note 1 - Description of Business and Summary of Significant Accounting Policies

Laramie Energy, LLC (the "Company") a Delaware limited liability company, was formed on May 10, 2012 by Laramie Energy II, LLC ("Laramie II") for the primary purpose of acquiring, owning, operating, and disposing of oil and gas properties in the continental United States of America. On August 31, 2012, Laramie II and Par Pacific Holdings, Inc. ("Par"), formerly named Par Petroleum Corporation, in connection with the Contribution Agreement ("Contribution Agreement") between Laramie II, Par, and the Company dated August 31, 2012, contributed certain oil- and gas-related assets and liabilities to the Company in exchange for a member interest in the Company and cash paid to Par. Since then, the Company has raised additional capital from the original and new members (see Note 10). At December 31, 2017 and 2016, the Company's properties were located in the Piceance Basin in Colorado. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

Cash and Cash Equivalents

The Company considers all highly liquid instruments purchased with a maturity of three months or less to be cash equivalents. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests. At December 31, 2017, cash and cash equivalents balance exceeded the federally insured limit by $35,111. The cash and cash equivalents balance did not exceed the federally insured limit as of December 31, 2016.

Concentrations of Credit Risk

The Company's producing properties are all located in Colorado in one general area, and the oil and gas production is sold to various purchasers based on market index prices. As of December 31, 2017 and 2016, two purchasers accounted for 93% and five purchasers accounted for 85% of accrued oil and gas revenue, respectively. For the year ended December 31, 2017 and 2016, three purchasers accounted for 71% and 72% of total revenues, respectively. For the year ended December 31, 2015, one purchaser accounted for 84% of total revenues. The Company continually monitors the credit standing of the primary purchasers.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Use of Estimates (continued)

Depreciation, depletion, and amortization of oil and gas properties and the impairment of proved oil and gas properties are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, including future costs to dismantle, dispose, and restore the Company's properties. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. In addition, significant estimates include the estimated cost and timing related to the asset retirement obligation, purchase price on a business combination (see Note 3), impairment of unproved oil and gas properties and the estimated fair value of derivative instruments.

Revenue Recognition

Oil and gas revenues are recognized when production volumes are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, persuasive evidence of a sales arrangement exists and collectability of the revenue is reasonably assured. The Company utilizes the entitlements method of accounting for natural gas sales revenues. Under this method, revenues for the entitlement share of gas produced are based on the working interest in the properties. The Company records a receivable (payable) to the extent it receives less (more) than its proportionate share of gas revenues. The Company recognizes condensate revenues and natural gas liquids revenues based on the amount of condensate and natural gas liquids sold and delivered to purchasers. Revenues are reported on a gross basis for the amounts received before taking into account production taxes, gathering and transportation expenses, and lease operating costs, which are reported as separate expenses. The Company's aggregate imbalance positions as of December 31, 2017 and 2016 were not significant.

Income Taxes

The Company has elected to be treated as a partnership for income tax purposes. Accordingly, taxable income and losses of the Company are reported on the income tax returns of the Company's members, and no provision for income taxes has been recorded on the accompanying financial statements.

The Company follows the guidance of Accounting Standards Codification ("ASC") Topic 740, *Income Taxes* . Interest and penalties associated with tax positions are recorded in the period assessed as general and administrative expenses. The Company's tax returns subject to examination by tax authorities include 2014 through the current period for state and federal tax reporting purposes, respectively.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Property and Equipment

The Company accounts for its oil and gas exploration and development activities under the successful efforts method of accounting. Under this method, costs of productive exploratory wells, all development wells and facilities, and undeveloped leases are capitalized when incurred. Oil and gas lease acquisition costs are also capitalized when incurred. Exploration costs, including personnel costs, geological and geophysical expenses, and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

The Company reviews its oil and gas properties for impairment at least annually and whenever events and circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares undiscounted future net cash flows to the assets' net book value. If the net capitalized costs exceed future net cash flows, then the cost of the property is written down to fair value. Fair value for oil and gas properties is generally determined based on discounted future net cash flows. In 2017, 2016, and 2015, the Company did not recognize an impairment expense relative to its proved oil and gas properties. Unproved oil and gas properties are assessed periodically, but at least annually, for impairment on a field basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, or future plans to develop acreage and allocate capital. The Company recognized impairment expense of $0, $0 and $12,272,304 for the periods ended December 31, 2017, 2016 and 2015, respectively.

The sale of a partial interest in a proved oil and gas property is accounted for as normal retirement, and no gain or loss is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to the ultimate recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A gain or loss is recognized for all other sales of producing and non-producing properties. There were no sales of proved oil and gas properties or unproved properties in 2017, 2016, or 2015.

Maintenance and repairs are charged to expense; renewals and betterments are capitalized to the appropriate property and equipment accounts. Upon retirement or disposition of assets, the costs and related accumulated depreciation are removed from the accounts with the resulting gains or losses, if any, reflected in results of operations.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Property and Equipment (continued)

The provision for depletion, depreciation, and amortization of oil and gas properties is calculated on a field basis based on proved reserves using the units-of-production method. Costs of certain facilities and equipment serving a number of properties are depreciated using the straight-line method over the estimated useful lives of the assets ranging from 7 to 15 years, or units-of-operations for certain significant equipment. The provisions for depreciation of the office furniture, equipment and other are calculated using the straight-line method over the estimated useful lives ranging from 5 to 15 years. Included in real estate and ranch property are buildings that are depreciated using the straight-line method over the estimated useful lives ranging from 20 to 39 years.

Derivative Instruments

The Company uses derivative instruments to manage its exposure to natural gas and natural gas liquids price volatility. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as assets or liabilities on the balance sheets. The Company has elected not to designate its derivatives as cash flow hedges. For derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded in gains and losses under the other income and expense caption in the statements of operations. When derivative contracts are settled, the Company also recognizes realized gains and losses under the other income and expense caption in its statements of operations.

Asset Retirement Obligation

Asset retirement obligations (“ARO”) relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The Company records the estimated fair value of an ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company reports a gain or loss upon settlement to the extent the actual costs differ from the recorded liability.

The majority of the Company’s ARO relates to the plugging and abandoning of oil and gas wells, the reclamation of the Company’s well locations and decommissioning and reclaiming water and compression facilities. Revisions to estimated ARO result in adjustments to the related capitalized asset and corresponding liability.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Asset Retirement Obligation (continued)

The following is a reconciliation of the ARO:

	For the Years Ended December 31, 2017	2016
Balance, beginning of period	$ 23,902,588	$ 7,294,893
Additions	2,039,180	55,061
Acquired oil and gas properties (Note 3)	—	15,532,801
Settlements and disposals	(241,364)	(40,631)
Accretion expense	1,285,890	1,060,464
Balance, end of period	$ 26,986,294	$ 23,902,588

Equity-Based Compensation

Compensation expense associated with equity-based awards is recognized at the fair value of the awards over the vesting period on a straight-line basis.

Reclassifications

Certain amounts in the 2015 and 2016 financial statements have been reclassified to conform to the 2017 presentation.

Recently Issued Accounting Pronouncements

In August 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-12, Derivatives and Hedging - Targeted Improvements to Accounting for Hedging Activities. The objective of this update is to improve the transparency of information about an entity's risk management activities and simplify the application of hedge accounting. ASU 2017-12 is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years, for public companies, and for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020, for private companies. Early application is permitted. The Company is currently evaluating the impact of adopting this standard.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Recently Issued Accounting Pronouncements (continued)

In January 2017, the FASB issued ASU 2017-01, Business Combinations - Clarifying the Definition of a Business. The objective of this update is to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of businesses. ASU 2017-01 is effective for the annual periods beginning after December 15, 2017, including interim periods within those periods, for public companies, and annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019, for private companies. The Company is currently evaluating the impact of adopting this standard.

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows-Classification of Certain Cash Receipts and Cash Payments. The objective of this update is to address eight specific cash flow issues in order to reduce the existing diversity in practice. ASU 2016-15 is effective for the fiscal years beginning after December 15, 2017, and interim periods within those fiscal years, for public companies, and fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019, for private companies. The Company is currently evaluating the impact of adopting this standard.

In February 2016, the FASB issued ASU 2016-02, Leases. The objective of this update is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, for public companies, and fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020, for private companies. The Company is currently evaluating the impact of adopting this standard.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. The objective of this update is to improve the recognition and measurement of financial instruments. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, for public companies, and for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019, for private companies. Early application is permitted for private companies as of the fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. The Company is currently evaluating the impact of adopting this standard.

Note 1 - Description of Business and Summary of Significant Accounting Policies (continued)

Recently Issued Accounting Pronouncements (continued)

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The objective of this update is to clarify the principles for recognizing revenue and to develop a common revenue standard. ASU 2015-14 deferred the effective reporting periods of ASU 2014-09, and it is effective for annual reporting periods beginning after December 15, 2017, including interim reporting periods within that reporting period, for public companies, and annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019, for private companies. Early application is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period, for public companies, and as of an annual reporting period beginning after December 15, 2016, including interim reporting periods within that reporting period, for private companies. The Company is currently evaluating the impact of adopting this standard.

Note 2 - Fair Value Measurements

Authoritative guidance defines estimated fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company’s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances.

The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, and are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. Substantially all Level 2 assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Note 2 - Fair Value Measurements (continued)

The assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's policy is to recognize transfers in and/or out of the fair value hierarchy as of the end of the reporting period in which the event or change in circumstances caused the transfer. The Company has consistently applied the valuation techniques discussed below in all periods presented. The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017 and 2016, by level within the fair value hierarchy:

	Level 1	Level 2	Level 3	Total
December 31, 2017				
Assets				
Derivative instruments, current	$ —	$ 2,983,243	$ —	$ 2,983,243
Liabilities				
Derivative instruments, current	$ —	$ 16,811	$ —	$ 16,811
December 31, 2016				
Liabilities				
Derivative instruments, current	$ —	$ 33,111,555	$ —	$ 33,111,555
Derivative instruments, non-current	$ —	$ 12,163,466	$ —	$ 12,163,466

As of December 31, 2017, the Company's commodity derivative financial instruments were comprised of 14 natural gas swaps and 3 costless collars. As of December 31, 2016, the Company's commodity derivative financial instruments were comprised of 24 natural gas swaps and 1 costless collar. The fair values of the swap agreements are determined under the income valuation technique using a discounted cash flows model. The fair values of the collar agreements are determined under the income valuation technique using an option-pricing model. The valuation models require a variety of inputs, including contractual terms, published forward prices, volatilities for options, and discount rates, as appropriate. The Company's estimates of fair value of derivatives include consideration of the counterparty's creditworthiness, the Company's creditworthiness, and the time value of money. The consideration of these factors results in an estimated exit price for each derivative asset or liability under a marketplace participant's view. All of the significant inputs are observable, either directly or indirectly; therefore, the Company's derivative instruments are included within the Level 2 fair value hierarchy. The counterparties in all of the Company's commodity derivative financial instruments are the lenders in the Company's bank credit facility.

Note 2 - Fair Value Measurements (continued)

Non-Recurring Fair Value Measurements

The treatment of the net assets acquired qualified as business combination and, as such, the Company estimated the fair value of each property as of the acquisition date (the date on which the Company obtained control of the properties) (see Note 3).

Fair value measurements utilize assumptions of market participants. To determine the fair value of the oil and gas assets related to the acquisition, the Company used an income approach based on a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. The Company determined the appropriate discount rates used for the discounted cash flow analyses by using a weighted average cost of capital from a market participant perspective plus property specific risk premiums for the assets acquired. The Company estimated property specific risk premiums taking into consideration that the related reserves are primarily natural gas, among other items. Given the unobservable nature of the significant inputs, they are deemed to be Level 3 in the fair value hierarchy. The additional net assets acquired were determined to be at fair value due to their short-term nature.

Financial Instruments

Other financial instruments not measured at fair value on a recurring basis include cash and cash equivalents, accounts receivable, accounts payable, oil and gas sales payable, accrued liabilities, notes payable and Class A Preferred units. With the exception of the notes payable and Class A Preferred units, the financial statement carrying amounts of these items approximate their fair values due to their short-term nature. The Company's note payable has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates. The fair value of the Company's Class A Preferred units approximates its carrying value based on the terms and conditions the Company can receive for similar financial instruments as of year-end.

Note 3 – Acquisitions

In the normal course of its business, the Company anticipates acquiring interests in proved oil and gas properties and in unproved acreage in its area of operations.

On December 17, 2015, the Company entered into an agreement to acquire certain properties in the Piceance Basin, from Oxy USA Inc. ("Oxy"), an oil and gas company, for $152.1 million. On March 1, 2016, the Company closed on its Purchase and Sale Agreement with Oxy.

The following table summarizes the purchase price and final allocation of the fair value of assets acquired and liabilities assumed:

Purchase Price	March 1, 2016
Oil and gas properties	
Proved	$ 135,952,475
Unproved	6,800,000
Real Estate	26,200,000
Other assets	848,000
Asset retirement obligations	(15,345,268)
Other Liabilities	(2,323,174)
	$ 152,132,033

Note 4 – Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of the following:

	December 31, 2017	December 31, 2016
Prepaid insurance	$ 429,361	$ 399,060
Prepaid rent	103,545	104,971
Prepaid royalties	603,500	410,900
Prepaid other	281,831	243,042
	$ 1,418,237	$ 1,157,973

Note 5 - Accrued Liabilities

Accrued liabilities, current, consist of the following:

	December 31, 2017	December 31, 2016
Accrued capital expenditures	$ 11,801,484	$ 4,069,400
Accrued production and property taxes	5,392,732	4,638,147
Accrued bonuses	2,725,409	2,621,286
Accrued joint developer prepayment	-	3,296,955
Accrued general and administrative expenses	183,341	129,888
Accrued lease operating expenses	1,837,222	1,051,622
Accrued other	1,324,176	1,089,434
	$ 23,264,364	$ 16,896,732

Note 6 - Credit Facility

On June 4, 2012, the Company entered into a credit facility (the "Facility"), as amended, with J.P. Morgan Securities, LLC and Wells Fargo Securities LLC, each as an arranger, JPMorgan Chase Bank, N.A. as the administrative agent (the "Administrative Agent"), and the lenders party thereto. The Facility is a $400 million secured revolving credit facility secured by a lien on the Company's oil and gas properties and related assets. The Facility matures on December 15, 2020.

Availability under the Facility is limited to the lesser of (i) $400 million or (ii) the borrowing base in effect from time to time. The borrowing base is determined by the Administrative Agent and the lenders, in their sole discretion, based on customary lending practices, review of the oil and gas properties included in the borrowing base, financial review of the Company, and such other factors as may be deemed relevant. The borrowing base is redetermined (i) on or about March 15 of each year based on the previous December 31 reserve report prepared by an independent engineering firm acceptable to the Administrative Agent, and (ii) on or about September 15 of each year based on the previous June 30 reserve report prepared by the Company's internal engineers. The borrowing base at December 31, 2017 was $230,000,000. At December 31, 2017, and 2016, the outstanding balance on the Facility was $171,500,000 and $117,500,000, respectively.

Note 6 - Credit Facility (continued)

During the year ended December 31, 2017, the Company incurred $211,087 of debt issuance costs in relation to the borrowing base redeterminations. Debt issuance costs incurred for the year ended December 31, 2016 were $1,485,493. The remaining unamortized debt issuance costs incurred in relation to the original Facility and the debt issuance costs incurred in relation to the amended Facility are being amortized straight-line over the life of the amended Facility.

Amounts borrowed bear interest at rates ranging from LIBOR plus 2.00% to LIBOR plus 3.00% per annum for Eurodollar loans and the prime rate plus 1.00% to prime rate plus 2.00% per annum for Base Rate loans, depending upon the ratio of outstanding credit to the borrowing base. At December 31, 2017, interest rates were between 3.74% and 4.06% for Eurodollar loans and 6.00% for Base Rate loans. At December 31, 2016, interest rates were between 3.14% and 3.27% for Eurodollar loans and 5.25% for Base Rate loans. Interest is due monthly on draw date of each Eurodollar and Base Rate loan. The agreement contains customary operational and financial covenants, including a current ratio covenant, and a total debt to consolidated EBITDAX (as defined) covenant. At December 31, 2017 and 2016, the Company was in compliance with all such covenants. Under the terms of the Facility, the Company is generally prohibited from making future cash distributions to its owners.

Note 7 - Derivative Instruments

The Company periodically enters into various commodity hedging instruments to mitigate a portion of the effect of natural gas and natural gas liquids price fluctuations. The Company classifies the fair value amounts of derivative assets and liabilities as net current or non-current derivative assets or net current or non-current derivative liabilities, whichever the case may be, by commodity and counterparty. The Company enters into derivatives under master netting arrangements, which, in an event of default, allows the Company to offset payables to and receivables from the defaulting counterparty. As of December 31, 2017 and 2016, there were no available amounts to be offset.

The Company's commodity derivative contracts as of December 31, 2017 are summarized below:

Collars	Basis	Average Quantity (MMBtu/Day)	Strike Price ($/MMBtu)
January 1, 2018 – March 31, 2018	NWPL	10,000	$3.00 – $3.25
January 1, 2018 – December 31, 2018	NYMEX	7,500	$2.85 – $3.25

Swaps	Basis	Average Quantity (MMBtu/Day)	Average Swap Price ($/MMBtu)
January 1, 2018 – December 31, 2018	NYMEX	87,857	$2.60 – $3.10

Basis Swaps	Basis	Average Quantity (MMBtu/Day)	Basis Differential ($/MMBtu)
January 1, 2018 – December 31, 2018	CIG	75,702	$ (0.24) – $ (0.28)

Note 7 - Derivative Instruments (continued)

The aggregate fair value of the Company's derivative instruments reported in the balance sheets, including the classification between current and non-current assets and liabilities, consists of the following:

		December 31, 2017	
		Gross Recognized Assets/ Liabilities	Net Recognized Fair Value Assets/ Liabilities
Derivative instruments	Current assets	$ 2,983,243	$ 2,983,243
Total derivative assets		$ 2,983,243	$ 2,983,243
Derivative instruments	Current liabilities	$ (16,811)	$ (16,811)
Total derivative liabilities		$ (16,811)	$ (16,811)

		December 31, 2016	
		Gross Recognized Assets/ Liabilities	Net Recognized Fair Value Assets/ Liabilities
Derivative instruments	Current liabilities	$ (31,111,555)	$ (31,111,555)
Derivative instruments	Non-current liabilities	(12,163,466)	(12,163,466)
Total derivative liabilities		$ (43,275,021)	$ (43,275,021)

None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's financial derivative contracts are high credit-quality financial institutions that are lenders under the Company's credit facility. The Company uses only credit facility participants to hedge with, since these institutions are secured equally with the holders of the Company's bank debt, which eliminates the potential need to post collateral when the Company is in a derivative liability position. As a result, the Company is not required to post letters of credit or company guarantees for its derivative counterparties in order to secure contract performance obligations.

Note 7 - Derivative Instruments (continued)

The table below summarizes the realized and unrealized gains and losses related to the Company's derivative instruments for the years ended December 31, 2017, 2016 and 2015.

		For the Years Ended December 31,		
Commodity Derivative Instrument	Location of Gain (Loss) Recognized	2017	2016	2015
Realized (losses) gains on derivative instruments, net	Other income (expense)	$ (10,710,922)	$ 6,723,873	$ 10,748,650
Unrealized gains (losses) on derivative instruments, net	Other income (expense)	46,241,453	(34,452,084)	(16,623,179)
Total realized and unrealized gains (losses) recorded, net	Other income (expense)	$ 35,530,531	$ (27,728,211)	$ (5,874,529)

Due to the volatility of oil and natural gas prices, the estimated fair values of the Company's commodity derivative instruments are subject to large fluctuations from period to period.

Note 8 – Commitments and Contingencies

The table below shows the Company's minimum future payments under non-cancellable operating leases as of December 31, 2017 and which are described below:

	Payments due by period						
	2018	2019	2020	2021	2022	Thereafter	Total
Office leases	1,084,296	1,103,979	1,121,561	330,263	—	—	3,640,099
Drilling rig contracts	1,728,000	—	—	—	—	—	1,728,000
Equipment leases	1,069,901	1,231,327	1,231,327	1,231,327	1,231,327	1,584,223	7,579,432
Other leases	76,326	76,326	76,326	51,079	—	—	280,057
Total	3,958,523	2,411,632	2,429,214	1,612,669	1,231,327	1,584,223	13,227,588

Non-cancelable Office Leases

The Company leases administrative office space in Denver, Colorado under an operating lease expiring May 31, 2021 and office space in Grand Junction, Colorado expiring December 31, 2020. Rental expense is recognized on a straight-line basis over the terms of the leases and was $1,181,612, $1,286,339 and $243,655 for the years ended December 31, 2017, 2016 and 2015. Prior to August 1, 2015, the Company had no office leases as all office space was provided by Laramie II under the terms of the Management Services Agreement.

Note 8 – Commitments and Contingencies (continued)

Drilling Rig Contracts

At December 31, 2017, the Company had two drilling rigs under contract, both expiring March 13, 2018. At December 31, 2016, the Company had one drilling rig under contract until May 2017 and was subsequently extended to March 2018. At December 31, 2015, the Company had one drilling rig under contract that was terminated on January 10, 2016; the Company expensed $133,875 relating to the termination of this contract.

Equipment Lease Financing

At December 31, 2017, the Company had two lease financing obligations pertaining to natural gas compressors with a major bank's leasing subsidiary. The leases expire in June 2023 and December 2024, respectively, at which time the Company may purchase the equipment at its fair market value. Rental expense was $648,499 and $347,360 for the years ended December 31, 2017 and 2016. The aggregate undiscounted minimum future lease payments are presented above.

Terminated Management Services Agreement

The Company entered into a Management Services Agreement with Laramie II effective August 31, 2012 whereby Laramie II provided management services and office space to the Company for $650,000 per month. The agreement was terminated effective August 1, 2015. After August 1, 2015, the Company directly incurred and settled general and administration services. For the year ended December 31, 2015, the Company paid management services fee to Laramie II of $4,550,000, which was included in general and administrative expenses in the statements of operations.

Employment Agreements

The Company has employment agreements with three of its executive officers.

Retirement Savings Plan

The Company outsources payroll and human resources functions to an administrative agent. In conjunction with this arrangement, the Company has a 401(k) plan (the "Plan") available to eligible employees. The Plan provides for up to 5% matching contributions by the Company. In 2017, 2016 and 2015, the Company's matching contributions to the Plan were $468,484, $346,558 and $57,255, respectively. Prior to August 1, 2015, the Company had no employees.

Note 8 – Commitments and Contingencies (continued)

Transportation, Gathering and Processing Agreements

Effective August 1, 2015, as part of the Management Agreement termination, the Company assumed from Laramie II a ship-or-pay agreement with an interstate pipeline company that extends through December 31, 2023. The transportation agreement obliges the Company to ship 15,000 MMBtu per day or pay the pipeline company a deficiency payment equal to an established tariff per MMBtu for the volume shortfall. For the past several years, because the Company did not utilize this firm capacity, the Company assigned the firm capacity to another shipper to partially offset this liability by supplementing the volumes that the Company did not ship. For the years ended December 31, 2017, 2016 and 2015, the Company incurred $771,893, $788,127 and $312,201, respectively, in deficiency payments for the volume shortfall which is included in general and administrative expenses in the statements of operations.

Gathering and Processing Agreements

At inception in August 2012, the Company assumed the long-term gas gathering and processing contracts of its predecessors. Subsequently, as other asset acquisitions have been made by the Company, other pre-existing long-term gas gathering and processing contracts tied to the acquired assets have been assumed by the Company. Accordingly, most of the Company's acreage in Mesa, Garfield, and Rio Blanco Counties, Colorado is dedicated to one or more of these gas gathering and processing contracts such that all of the Company's gas production flows through third party midstream companies for gathering and processing. Only one of these contracts requires a minimum annual volume commitment, and this contract's volume commitment ends in November 2019. Under this contract, should the Company not ship the required volumes in a particular year prior to 2019, it must pay the gatherer a deficiency payment equal to the gathering fee for the volume shortfall. During the years ended December 31, 2017, 2016 and 2015, the Company incurred gas gathering expense related to this volume shortfall of $1,177,689 $1,432,100, and $1,429,305, respectively, which is paid in the following January each year which is included in Gathering, transportation and processing expense. At December 31, 2017 and 2016, the Company had the respective 2017 and 2016 gas volume deficiency expenses under this contract included in accounts payable.

Effective January 1, 2017, the Company amended one of its gathering and processing contracts. Under the terms of the amendment, the Company received reduced gathering and processing fees in return for a commitment to drill and complete a total 150 wells by December 31, 2018, 50 of which were required to be drilled and completed by December 31, 2017. If the commitment to drill and complete 50 wells was not met by December 31, 2017, the reduction in gathering and processing fees would be subject to a clawback payment. The Company met the commitment to drill and complete 50 wells in 2017, thus eliminating the clawback provision. Should the Company fall short of the total 150 well commitment for the 2017-18 period by December 31, 2018, a penalty will be due to the gas gatherer and processor for each well short of the 150 well target.

Note 8 – Commitments and Contingencies (continued)

Other Minimum Volume Obligations Relating to Gathering and Processing Agreements

Upon closing of the asset acquisition from Oxy on March 1, 2016 (see Note 3), the Company acquired Oxy's oil and gas leases, gas wells, and its gathering and processing agreements to which the acquired gas wells and lease acreage were dedicated. As a key provision of the contractual assignment of Oxy's former gathering and processing contracts to the Company, Oxy retained all of the deficiency payment liabilities of the underlying gathering and processing contracts' minimum volume obligations between Oxy and the gathering and processing companies. Per the terms of the asset acquisition, and to partially offset Oxy's retained deficiency payment liabilities, the Company entered into four separate minimum volume commitment agreements directly between Oxy and the Company. Under each of these minimum volume commitment agreements, the Company must pay Oxy a monthly deficiency payment for the difference between the committed volumes and the actual volumes shipped under Oxy's former gathering and processing contracts that were assigned to the Company. Each of these four minimum volume commitment agreements relate to one of the four separate gathering and processing contracts that Oxy assigned to the Company.

Each of the Company's four minimum volume agreements with Oxy have a separate monthly gas volume schedule. Under two of the agreements between the Company and Oxy, the minimum gas volume schedules are based on the Company's forecast of future gas production from the existing proved developed wells that are dedicated to the two assumed gathering and processing contracts. The minimum volume schedules of the other two agreements between the Company and Oxy are based on the Company's forecast of existing proved developed wells and, starting in January 2018, also from future wells that the Company plans to drill within the acquired acreage. Based on the Company's capital expenditure plans to drill new wells as approved by its Board of Directors and the Company's forecast of its future gas production, the Company projects that no material amounts shall be due to the asset seller under these four minimum volume obligations. For the year ended December 31, 2017 and 2016, the Company incurred $228,713 and $63,978, in deficiency payments for the volume shortfall which is included in gathering, transportation and processing expenses in the statements of operations.

Litigation

The Company is subject to litigation, claims and governmental regulatory proceedings arising in the course of ordinary business. No litigation or governmental regulatory proceedings are currently underway or pending.

Environmental Matters

As an owner or lessee and operator of oil and gas properties, the Company is subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. The Company has policies to ensure continuing compliance with environmental laws and regulations and maintains insurance coverage for certain environmental matters. There can be no assurance that current or future federal, state, or local laws and regulations will not require the Company to spend material amounts to comply with such laws and regulations.

Note 9 – Preferred A Units

Under the Unit Purchase Agreement ("UPA 2016") dated February 22, 2016, the Company issued 30,000 Class A Preferred units at $1,000 per unit. The Class A Preferred units have liquidation preference rights over the Class A units. Dividends due on the Class A Preferred units are 10% per annum and due on a quarterly basis if paid in cash. The Company may elect to accrue dividends and increase the liquidation preference of the Class A Preferred units at 12% per annum on a quarterly compounding basis. During 2017 and 2016, the Company incurred non-cash preferred dividend expense of $4,166,112 and $3,193,820, respectively.

The Company has classified the Class A Preferred units as debt due to the mandatorily redeemable feature. The Class A Preferred units are redeemable six years from the date of the UPA 2016, February 22, 2022. Under ASC Topic 470, *Debt* , the proceeds of debt instruments should be allocated based upon their relative fair values. In connection with the issuance of the 30,000 Class A Preferred units in exchange for $30,000,000, the purchaser, Wells Fargo Central Pacific Holdings, Inc. ("Wells Fargo"), received 12,992 Class A units. The Company used a market based approach to a "Backsolve" method to identify the relative fair values of the Class A Preferred units and Class A units, $27,689,935 and $2,310,065, respectively, upon issuance.

Note 10 – Members' Equity

The Company issued additional Class A units to existing members under UPA 2016. Members purchased 195,530 Class A units at $358 per Class A unit for $70,000,000. In addition, the Company issued 12,992 Class A units to Wells Fargo (see Note 9).

All Class A unit holders vote as a single class based upon their respective sharing percentages. Revenues and costs are allocated in accordance with specific provisions in the Third Amended and Restated LLC Agreement ("3 rd LLC Agreement"). After payout to the Class A Preferred units, the Class A units are senior to Class B units in terms of liquidation and voting and have first-call on all assets until the Class A units reach payout as defined in the 3 rd LLC Agreement.

	Class A Units	
	Units	Amount
Balances, December 31, 2015	657,612	458,903,741
UPA 2016 – February 22, 2016	208,522	72,310,065
Funding fees and other costs of raising capital	—	(423,992)
Balances, December 31, 2016	866,134	530,789,814
Balances, December 31, 2017	866,134	530,789,814

Note 10 – Members' Equity (continued)

Class B Units

Laramie Energy Employee Holdings, LLC ("Employee Holdings") (FKA Piceance Energy Employee Holdings, LLC) was formed on August 28, 2015 by the Management Investors of Laramie Energy Employee Holding, LLC ("Management Investors") and holds all 15,000, Class B units authorized under the Company's Second Amended and Restated Limited Liability Company Agreement (the "LLC Agreement"). Employee Holdings is authorized to grant the Class B units to selected Company employees (including the Management Investors) upon written consent from the Company in its capacity as Manager of Employee Holdings. As of December 31, 2017, Employee Holdings had granted 14,235 Class B units, net of forfeitures, to the Company's employees.

Class B units generally vest over three years. As of December 31, 2017, 2016 and 2015, vested Class B units were 8,723, 4,208 and 0, respectively. If an employee is terminated by the Company for cause, all Class B units, whether vested or unvested at the time of termination, shall be deemed automatically forfeited. Employees who cease to be employed by the Company for any reason, other than termination for cause, will forfeit all unvested units. Vested units may be repurchased by the Company at fair value at the Company's option. Distributions to Class B unit holders will only occur after the Class A unit holders reach "pay-out" as defined in the LLC Agreement. Generally, Class A unit holders are entitled to receive the return of their investment in the Company's Class A units plus a specified internal rate of return on such investment prior to the Class B unit holders receiving any cash distributions.

The Company's Class B units are non-voting "profits interests" for which no cash consideration was received upon issuance and which are used to compensate management based on the value of the Company. The Company accounts for the Class B units as an equity award and has recorded compensation expense to date based on the grant dates' fair values and the vesting periods. The estimated fair value of the Class B units at grant date July 1, 2017, July 1, 2016 and August 31, 2015 was approximately $0.1 million, $0.8 million and $19.3 million, respectively. In 2017, employees forfeited 550 Class B units which reduced compensation cost by $0.5 million. In 2016, employees forfeited 425 Class B units which reduced compensation cost by $0.6 million. In 2015, there were no forfeitures of Class B units. Total compensation cost recognized during 2017, 2016 and 2015 was approximately $6.2 million, $6.6 million and $2.6 million, respectively, and is included in general and administrative expense in the accompanying statements of operations. Approximately $3.4 million in compensation expense will be recognized over the remaining 2.5 years. Estimated fair values were determined considering the following factors:

- Estimating the fair value of the Company at the dates on which units were awarded and the balance sheet date based on investments in Class A units.
- Allocating the Company's fair value to the unit holders through application of the Option Pricing Method as detailed in the AICPA Accounting and Valuation Guide, *Valuation of Privately-Held-Company Equity Securities Issued as Compensation* .

Note 10 – Members' Equity (continued)

Class B Units (continued)

As part of the Option Pricing Method, a series of Black-Scholes option pricing models were applied in order to model the value to the Class B units as a contingent claim on the upside value of the Company's equity value. The assumptions listed below were made in applying this option pricing model:

- The underlying equity value was solved such that the value allocable to the Class A units aligned to the investment values of $400, $358 and $595.50 per share of the Company at July 1, 2017, July 1, 2016 and August 31, 2015, respectively. This approach is referred to as the "Backsolve" method in the AICPA guide.
- The exercise prices of the options were based upon the participation thresholds at which the participation ratios of liquidation proceeds change between Class A and B. These amounts were derived based on the rights and preferences outlined in Company's LLC Agreement.
- The maturity dates of the options were assumed to be three years from the grant date, aligning to the expected investment holding period.
- Volatility was based on the volatilities of comparable companies and was estimated at 41% as of the grant dates.

The risk-free rate was based on U.S. Treasury Strips, which corresponded with the assumed term (three years) of the options at grant date at 1.24%, 0.71 % and 1.04% as of the grant dates, July 1, 2017, July 1, 2016 and August 31, 2015, respectively.

Note 11 – Subsequent Events

Acquisition

On February 28, 2018, the Company closed on a Purchase and Contribution Agreement with another exploration and production company (the "New LLC Member"), whereby the New LLC Member contributed all of its oil and gas properties located in the Piceance Basin, with the associated obligations under operating contracts, and a $20 million cash payment, collectively with a fair market value of $28.1 million, into the Company in exchange for 70,227 of the Company's newly issued Class A Units. The Purchase and Contribution Agreement is subject to customary adjustments which will be settled in cash. In addition, the New LLC Member provided the Company with a $3.5 million cash payment for asset reclamation liabilities related to the properties conveyed.

The Company has evaluated all subsequent events through the independent auditors' report date, March 9, 2018, which is the date the financial statement were available for issuance.