Alon USA Partners, LP
Form 10-Q
October 31, 2014

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

FORM 10-Q

þ	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2014
OR	
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM __________TO __________

Commission file number: 001-35742
ALON USA PARTNERS, LP
(Exact name of Registrant as specified in its charter)

Delaware (State of organization)	46-0810241 (I.R.S. Employer Identification No.)

12700 Park Central Dr., Suite 1600, Dallas, Texas 75251
(Address of principal executive offices) (Zip Code)

(972) 367-3600
(Registrant's telephone number, including area code)

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 þ No o
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 þ No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act:
Large accelerated filer o   Accelerated filer þ   Non-accelerated filer o   Smaller reporting company o

Indicate by check whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ
The number of the Registrant's common limited partner units outstanding as of October 24, 2014, was 62,506,550.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	September 30, 2014 (unaudited)	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$115,295	$153,583
Accounts and other receivables, net	108,524	123,781
Accounts and other receivables, net - related parties	15,212	14,621
Inventories	58,815	49,146
Prepaid expenses and other current assets	12,129	4,642
Total current assets	309,975	345,773
Property, plant and equipment, net	452,489	472,885
Other assets, net	79,971	31,266
Total assets	$842,435	$849,924
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$257,598	$280,774
Accrued liabilities	39,081	44,492
Current portion of long-term debt	2,500	2,500
Total current liabilities	299,179	327,766
Other non-current liabilities	42,870	34,894
Long-term debt	290,358	341,822
Total liabilities	632,407	704,482
Commitments and contingencies (Note 11)		
Partners' equity:		
General Partner	—	—
Common unitholders - 62,506,550 and 62,502,467 units issued and outstanding at September 30, 2014 and December 31, 2013, respectively	210,028	145,442
Total partners' equity	210,028	145,442
Total liabilities and partners' equity	$842,435	$849,924

The accompanying notes are an integral part of these consolidated financial statements.

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ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(unaudited, dollars in thousands except per unit data)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
Net sales (1)	$838,882	$881,902	$2,421,194	$2,551,763
Operating costs and expenses:				
Cost of sales	701,331	844,423	2,125,775	2,261,948
Direct operating expenses	25,723	26,281	79,816	84,017
Selling, general and administrative expenses	8,353	4,134	19,505	16,864
Depreciation and amortization	13,852	10,975	33,427	34,282
Total operating costs and expenses	749,259	885,813	2,258,523	2,397,111
Loss on disposition of assets	—	(21)	—	(21)
Operating income (loss)	89,623	(3,932)	162,671	154,631
Interest expense	(11,584)	(12,127)	(34,477)	(30,489)
Other income, net	14	—	627	18
Income (loss) before state income tax expense	78,053	(16,059)	128,821	124,160
State income tax expense	1,060	61	1,785	1,434
Net income (loss)	$76,993	$(16,120)	$127,036	$122,726
Earnings (loss) per unit	$1.23	$(0.26)	$2.03	$1.96
Weighted average common units outstanding (in thousands)	62,507	62,502	62,505	62,502
Cash distribution per unit	$0.13	$0.71	$1.00	$2.76

(1) Includes sales to related parties of $156,131 and $164,338 for the three months and $447,314 and $462,280 for the nine months ended September 30, 2014 and 2013, respectively.

The accompanying notes are an integral part of these consolidated financial statements.

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ALON USA PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited, dollars in thousands)

	For the Nine Months Ended September 30,	
	2014	2013
Cash flows from operating activities:		
Net income	$127,036	$122,726
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	33,427	34,282
Loss on disposition of assets	—	21
Amortization of debt issuance costs	1,535	1,488
Amortization of original issuance discount	411	380
Changes in operating assets and liabilities:		
Accounts and other receivables, net	15,257	5,519
Accounts and other receivables, net - related parties	(591)	(93)
Inventories	(9,669)	(19,165)
Prepaid expenses and other current assets	(7,487)	(774)
Other assets, net	(1,334)	(216)
Accounts payable	(22,407)	5,674
Accrued liabilities	(4,780)	5,535
Other non-current liabilities	7,976	4,342
Net cash provided by operating activities	139,374	159,719
Cash flows from investing activities:		
Capital expenditures	(13,931)	(16,634)
Capital expenditures for turnarounds and catalysts	(49,150)	(5,024)
Net cash used in investing activities	(63,081)	(21,658)
Cash flows from financing activities:		
Distributions paid to unitholders	(11,506)	(31,746)
Distributions paid to unitholders - Alon Energy	(51,000)	(140,760)
Inventory agreement transactions	(200)	—
Deferred debt issuance costs	—	(205)
Revolving credit facility, net	(50,000)	31,000
Payments on long-term debt	(1,875)	(1,875)
Net cash used in financing activities	(114,581)	(143,586)
Net decrease in cash and cash equivalents	(38,288)	(5,525)
Cash and cash equivalents, beginning of period	153,583	66,001
Cash and cash equivalents, end of period	$115,295	$60,476
Supplemental cash flow information:		
Cash paid for interest, net of capitalized interest	$33,745	$29,538
Cash paid for income tax	$1,785	$1,434
Supplemental disclosure of non-cash activity:		
Capital expenditures included in accounts payable and accrued liabilities	$5,620	$—

The accompanying notes are an integral part of these consolidated financial statements.

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ALON USA PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited, dollars in thousands except as noted)

(1) Basis of Presentation

As used in this report, the terms "Alon," the "Partnership," "we," "us" or "our" refer to Alon USA Partners, LP, one or more of its consolidated subsidiaries or all of them taken as a whole. References in this report to "Alon Energy" refer collectively to Alon USA Energy, Inc. and its consolidated subsidiaries, other than Alon USA Partners, LP, its subsidiaries and its general partner.

We are a Delaware limited partnership formed in August 2012 by Alon Energy and its wholly-owned subsidiary Alon USA Partners GP, LLC (the "General Partner"). On November 26, 2012, we completed our initial public offering of 11,500,000 common units representing limited partner interests. Our General Partner is owned 100% by Alon Energy and holds all of the non-economic general partner interests in the Partnership.

These consolidated financial statements and notes are unaudited and have been prepared in accordance with United States generally accepted accounting principles ("GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities Exchange Act of 1934. Accordingly, they do not include all of the information and notes required by GAAP for complete consolidated financial statements.

In the opinion of the General Partner's management, the information included in these consolidated financial statements reflects all adjustments, consisting of normal and recurring adjustments, which are necessary for a fair presentation of our consolidated financial position and results of operations for the interim periods presented. All significant intercompany balances and transactions have been eliminated in consolidation. Certain prior year balances may have been aggregated or disaggregated in order to conform to the current year presentation. Our results of operations for the nine months ended September 30, 2014 are not necessarily indicative of the operating results that may be realized for the year ending December 31, 2014.

Our consolidated balance sheet as of December 31, 2013 has been derived from the audited financial statements as of that date. These unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2013.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board and the International Accounting Standards Board jointly issued a comprehensive new revenue recognition standard that provides accounting guidance for all revenue arising from contracts to provide goods or services to customers. This standard is intended to improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets. The requirements from the new standard are effective for interim and annual periods beginning after December 15, 2016, and early adoption is not permitted. The standard allows for either full retrospective adoption or modified retrospective adoption. We are evaluating the guidance to determine the method of adoption and the impact of this standard on our consolidated financial statements.

(2) Fair Value

We determine fair value as 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. We classify financial assets and financial liabilities into the following fair value hierarchy:

- Level 1 - valued based on quoted prices in active markets for identical assets and liabilities;
- Level 2 - valued based on quoted prices for similar assets and liabilities in active markets, and inputs other than quoted prices that are observable for the asset or liability; and
- Level 3 - valued based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities.

As required, we utilize valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy. We generally apply the "market approach" to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

(unaudited, dollars in thousands except as noted)

The carrying amounts of our cash and cash equivalents, receivables, payables and accrued liabilities approximate fair value due to the short-term maturities of these assets and liabilities. The reported amounts of long-term debt approximate fair value. Derivative instruments are carried at fair value, which are based on quoted market prices. Derivative instruments and the Renewable Identification Numbers (“RINs”) obligation are our only assets and liabilities measured at fair value on a recurring basis.

The RINs obligation represents the period-end deficit, if any, after considering any RINs acquired or under contract, necessary to meet our requirements to blend biofuels into the products we have produced. The RINs obligation is categorized as level 2 of the fair value hierarchy and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

The following table sets forth the assets and liabilities measured at fair value on a recurring basis, by input level, in the consolidated balance sheets at September 30, 2014 and December 31, 2013:

	Level 1	Level 2	Level 3	Total
As of September 30, 2014				
Liabilities:				
Commodity contracts (futures and forwards)	$717	$—	$—	$717
Fair value hedge	—	878	—	878
As of December 31, 2013				
Assets:				
Commodity contracts (futures and forwards)	$22	$—	$—	$22
Liabilities:				
Fair value hedge	—	2,304	—	2,304
RINs obligation	—	334	—	334

(3) Derivative Financial Instruments

We selectively utilize crude oil and refined product commodity derivative contracts to reduce the risk associated with potential price changes on committed obligations as well as to reduce earnings volatility. We do not speculate using derivative instruments. Credit risk on our derivative instruments is mitigated by transacting with counterparties meeting established collateral and credit criteria.

Mark to Market

We have certain contracts that serve as economic hedges, which are derivatives used for risk management but not designated as hedges for financial accounting purposes. All economic hedge transactions are recorded at fair value and any changes in fair value between periods are recognized in earnings.

We have contracts that are used to fix prices on forecasted purchases of inventory. Forwards represent physical trades for which pricing and quantities have been set, but the physical product delivery has not occurred by the end of the reporting period. Futures represent trades executed on the New York Mercantile Exchange which have not been closed or settled at the end of the reporting period.

Fair Value Hedge

Fair value hedges are used to hedge price volatility of certain refining inventories and firm commitments to purchase inventories. The gain or loss on a derivative instrument designated and qualifying as a fair value hedge, as well as the offsetting gain or loss on the hedged item attributable to the hedged risk, is recognized in earnings in the same period. As of September 30, 2014, we have accounted for certain commodity contracts as fair value hedges with contract purchase volumes of 333 thousand barrels of crude oil with remaining contract terms through May 2019.

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ALON USA PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(unaudited, dollars in thousands except as noted)

The following tables present the effect of derivative instruments on the consolidated statements of financial position:

	As of September 30, 2014			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments:				
Commodity contracts (futures and forwards)	Accounts receivable	$1,678	Accrued liabilities	$2,395
Total derivatives not designated as hedging instruments		$1,678		$2,395
Derivatives designated as hedging instruments:				
Fair value hedge		$—	Other non-current liabilities	$878
Total derivatives designated as hedging instruments		—		878
Total derivatives		$1,678		$3,273

	As of December 31, 2013			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments:				
Commodity contracts (futures and forwards)	Accounts receivable	$303	Accrued liabilities	$281
Total derivatives not designated as hedging instruments		$303		$281
Derivatives designated as hedging instruments:				
Fair value hedge		$—	Other non-current liabilities	$2,304
Total derivatives designated as hedging instruments		—		2,304
Total derivatives		$303		$2,585

The following tables present the effect of derivative instruments on the consolidated statements of operations:

Derivatives in fair value hedging relationships:

		Gain (Loss) Recognized in Income			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	Location	2014	2013	2014	2013
Fair value hedge	Cost of sales	$3,818	$(2,232)	$1,426	$(3,830)
Total derivatives		$3,818	$(2,232)	$1,426	$(3,830)

Derivatives not designated as hedging instruments:

		Gain (Loss) Recognized in Income			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	

	Location	2014	2013	2014	2013
Commodity contracts (futures & forwards)	Cost of sales	$(2,329)	$(2,091)	$(4,604)	$4,559
Total derivatives		$(2,329)	$(2,091)	$(4,604)	$4,559

(unaudited, dollars in thousands except as noted)

Offsetting Assets and Liabilities

Our commodity derivative financial instruments are subject to master netting arrangements to manage counterparty credit risk associated with derivatives and we offset the fair value amounts recorded for derivative instruments to the extent possible under these agreements on our consolidated balance sheets.

The following table presents offsetting information regarding our derivatives by type of transaction as of September 30, 2014 and December 31, 2013:

	Gross Amounts of Recognized Assets/Liabilities	Gross Amounts offset in the Statement of Financial Position	Net Amounts Presented in the Statement of Financial Position	Gross Amounts Not offset in the Statement of Financial Position		Net Amount
				Financial Instruments	Cash Collateral Pledged	
As of September 30, 2014						
Derivative Assets:						
Commodity contracts (futures & forwards)	$ 1,833	$(155)	$1,678	$(1,678)	$—	$—
Derivative Liabilities:						
Commodity contracts (futures & forwards)	$ 2,550	$(155)	$2,395	$(1,678)	$—	$717
Fair value hedge	878	—	878	—	—	878
As of December 31, 2013						
Derivative Assets:						
Commodity contracts (futures & forwards)	$ 514	$(211)	$303	$(281)	$—	$22
Derivative Liabilities:						
Commodity contracts (futures & forwards)	$ 492	$(211)	$281	$(281)	$—	$—
Fair value hedge	2,304	—	2,304	—	—	2,304

Compliance Program Market Risk

We are obligated by government regulations to blend a certain percentage of biofuels into the products we produce that are consumed in the U.S. We purchase biofuels from third parties and blend those biofuels into our products, and each gallon of biofuel purchased includes a RIN. To the degree we are unable to blend biofuels at the required percentage, a RINs deficit is generated and we must acquire that number of RINs by the annual reporting deadline in order to remain in compliance with applicable regulations.

We are exposed to market risk related to the volatility in the price of credits needed to comply with these government regulations. We manage this risk by purchasing RINs when prices are deemed favorable utilizing fixed price purchase contracts. Some of these contracts are derivative instruments; however, we elect the normal purchase and sale exception and do not record these contracts at their fair values.

The cost of meeting our obligations under these compliance programs was $2,590 and $1,178 for the three months ended and $4,757 and $9,194 for the nine months ended September 30, 2014 and 2013, respectively. These amounts are reflected in cost of sales.

(4) Inventories

Our inventories (including inventory consigned to others) are stated at the lower of cost or market. Cost is determined under the last-in, first-out (LIFO) method for crude oil, refined products and blendstock inventories. Materials and supplies are stated at average cost.

(unaudited, dollars in thousands except as noted)

Carrying value of inventories consisted of the following:

	September 30, 2014	December 31, 2013
Crude oil, refined products and blendstocks	$28,889	$25,246
Crude oil inventory consigned to others	20,490	14,214
Materials and supplies	9,436	9,686
Total inventories	$58,815	$49,146

Market values of crude oil, refined products and blendstock inventories exceeded LIFO costs by $17,657 and $21,216 at September 30, 2014 and December 31, 2013, respectively.

(5) Inventory Financing Agreement

The Partnership has a Supply and Offtake Agreement and other associated agreements (together the “Supply and Offtake Agreement”) with J. Aron & Company (“J. Aron”). Pursuant to the Supply and Offtake Agreement, (i) J. Aron agreed to sell to us, and we agreed to buy from J. Aron, at market prices, crude oil for processing at the Big Spring refinery and (ii) we agreed to sell to J. Aron, and J. Aron agreed to buy from us, at market prices, certain refined products produced at the Big Spring refinery.

The Supply and Offtake Agreement also provided for the sale, at market prices, of our crude oil and certain refined product inventories to J. Aron, the lease to J. Aron of crude oil and refined product storage facilities, and to identify prospective purchasers of refined products on J. Aron’s behalf. The Supply and Offtake Agreement has an initial term that expires in May 2019. J. Aron may elect to terminate the Supply and Offtake Agreement prior to the expiration of the initial term beginning in May 2016 and upon each anniversary thereof, on six months prior notice. We may elect to terminate in May 2018 on six months prior notice.

Following expiration or termination of the Supply and Offtake Agreement, we are obligated to purchase the crude oil and refined product inventories then owned by J. Aron and located at the Big Spring refinery at then current market prices. Financing charges related to the Supply and Offtake Agreement are recorded as interest expense in the consolidated statements of operations.

At September 30, 2014 and December 31, 2013, we had net current payables of $2,690 and net current receivables of $11,640, respectively, from J. Aron for sales and purchases, non-current liabilities related to the original financing of $32,394 and $24,482, respectively, and a consignment inventory receivable representing a deposit paid to J. Aron of $6,290 and $6,290, respectively.

Additionally, we had current payables of $2,332 and $263 at September 30, 2014 and December 31, 2013, respectively, for forward commitments related to month-end consignment inventory target levels differing from projected levels and the associated pricing with these inventory level differences.

(6) Property, Plant and Equipment, Net

Property, plant and equipment, net consisted of the following:

	September 30, 2014	December 31, 2013
Refining facilities	$682,898	$677,085
Accumulated depreciation	(230,409)	(204,200)
Property, plant and equipment, net	$452,489	$472,885

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ALON USA PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(unaudited, dollars in thousands except as noted)

(7) Additional Financial Information
The following tables provide additional financial information related to the consolidated financial statements.
(a) Other Assets, Net

	September 30, 2014	December 31, 2013
Deferred debt issuance costs	$6,247	$7,782
Receivable from supply agreement	6,290	6,290
Deferred turnaround and catalyst cost	58,357	7,774
Other	9,077	9,420
Total other assets	$79,971	$31,266

(b) Accrued Liabilities and Other Non-Current Liabilities

	September 30, 2014	December 31, 2013
Accrued Liabilities:		
Taxes other than income taxes, primarily excise taxes	$24,001	$30,354
Employee costs	2,170	1,500
Accrued finance charges	539	1,365
Environmental accrual (Note 11)	1,307	1,307
Commodity contracts	2,395	281
Other	8,669	9,685
Total accrued liabilities	$39,081	$44,492
Other Non-Current Liabilities:		
Consignment inventory obligation	$32,394	$24,482
Environmental accrual (Note 11)	5,640	5,640
Asset retirement obligations	2,037	1,973
Other	2,799	2,799
Total other non-current liabilities	$42,870	$34,894

(8) Indebtedness
Debt consisted of the following:

	September 30, 2014	December 31, 2013
Term loan credit facility	$242,858	$244,322
Revolving credit facility	50,000	100,000
Total debt	292,858	344,322
Less: Current portion	2,500	2,500
Total long-term debt	$290,358	$341,822

Outstanding letters of credit under the revolving credit facility were $90,656 and $109,772 at September 30, 2014 and December 31, 2013, respectively.
Our revolving credit facility contains maintenance financial covenants. At September 30, 2014, we were in compliance with these covenants.

(unaudited, dollars in thousands except as noted)

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(9) Partners' Equity (unit values in dollars)

Cash Distributions

We have adopted a policy pursuant to which we will distribute all of the available cash generated each quarter, as defined in the partnership agreement, subject to the approval of the board of directors of the General Partner, within 60 days following the end of such quarter.

During the nine months ended September 30, 2014, we paid the following cash distributions:

Date Paid	Distribution Amount Per Unit	Total Distribution Amount
March 3, 2014	$0.18	$11,250
May 21, 2014	0.69	43,130
August 25, 2014	0.13	8,126

Restricted Units

In May 2014, we granted awards to non-employee directors of the General Partner of 4,083 restricted common units at a grant date price of $18.38 per unit, which vest over a period of three years, assuming continued service at vesting.

(10) Related-Party Transactions

Sales and Receivables

Sales to related parties include motor fuels and asphalt sold to other Alon Energy subsidiaries at prices substantially determined by reference to market commodity pricing information. These sales are included in net sales in the consolidated statements of operations. Accounts receivable from related parties include sales of motor fuels and are shown separately on the consolidated balance sheets.

Costs Allocated from Alon Energy

The Partnership is a subsidiary of Alon Energy and is operated as a component of the integrated operations of Alon Energy. As such, the executive officers of Alon Energy, who are employed by another subsidiary of Alon Energy, also serve as executive officers of the General Partner and Alon Energy’s other subsidiaries.

(a) Corporate Overhead Allocations

Alon Energy performs general corporate and administrative services and functions for us and their other subsidiaries, which include accounting, treasury, cash management, tax, information technology, insurance administration and claims processing, legal, environmental, risk management, audit, payroll and employee benefit processing and internal audit services. Alon Energy allocates the expenses actually incurred in performing these services to the Partnership based primarily on the estimated amount of time the individuals performing such services devote to our business and affairs relative to the amount of time they devote to the business and affairs of Alon Energy’s other subsidiaries. The management of Alon Energy and the General Partner consider these allocations to be reasonable. We record the amount of such allocations as selling, general and administrative expenses. Our allocation for selling, general and administrative expenses were $2,486 and $2,124, for the three months ended September 30, 2014 and 2013, respectively, and $8,454 and $8,568 for the nine months ended September 30, 2014 and 2013, respectively.

(b) Labor Costs

As we are operated as a component of Alon Energy’s integrated operations, we have no employees. As a result, employee expense costs for Alon Energy employees working in our operations have been allocated to us and recorded as payroll expense in direct operating expenses. The allocated portion of Alon Energy’s employee expense costs included in direct operating expenses were $6,485 and $6,211 for the three months ended September 30, 2014 and 2013, respectively, and $20,191 and $18,169 for the nine months ended September 30, 2014 and 2013, respectively.

(c) Insurance Costs

Insurance costs related to the Big Spring refinery and wholesale marketing operations are allocated to us by Alon Energy based on estimated insurance premiums on a stand-alone basis relative to Alon Energy’s total insurance premium. Our allocation for insurance costs included in direct operating expenses were $1,799 and $3,038 for the three months ended September 30, 2014 and 2013, respectively, and $5,435 and $8,300 for the nine months ended September 30, 2014 and 2013, respectively.

Leasing Agreements

In June 2014, we entered into six year lease agreements with a subsidiary of Alon Energy to lease equipment at the Big Spring refinery. The lease agreements were effective July 1, 2014 and require fixed monthly payments amounting to $4,920 annually. Rent payments were $1,230 and $1,230 for the three and nine months ended September 30, 2014, respectively.

These agreements were reviewed and approved by the Conflicts Committee of the General Partner.

Distributions

During the nine months ended September 30, 2014, we paid cash distributions of $62,506, or $1.00 per unit. Total cash distributions paid to Alon Energy were $51,000. During the nine months ended September 30, 2013, we paid cash distributions of $172,506, or $2.76 per unit. Total cash distributions paid to Alon Energy were $140,760.

(11) Commitments and Contingencies

(a) Commitments

In the normal course of business, we have long-term commitments to purchase, at market prices, utilities such as natural gas, electricity and water for use by our refinery, terminals and pipelines. We are also party to various refined product and crude oil supply and exchange agreements, which are typically short-term in nature or provide terms for cancellation.

(b) Contingencies

We are involved in various legal actions arising in the ordinary course of business. We believe the ultimate disposition of these matters will not have a material effect on our financial position, results of operations or liquidity.

(c) Environmental

We are subject to loss contingencies pursuant to federal, state, and local environmental laws and regulations. These laws and regulations govern the discharge of materials into the environment and may require us to incur future obligations to investigate the effects of the release or disposal of certain petroleum, chemical, and mineral substances at various sites; to remediate or restore these sites and to compensate others for damage to property and natural resources. These contingent obligations relate to sites owned by the Partnership and are associated with past or present operations. We are currently participating in environmental investigations, assessments and cleanups pertaining to the refinery, pipelines and terminals. We may be involved in additional future environmental investigations, assessments and cleanups. The magnitude of future costs are unknown and will depend on factors such as the nature and contamination at many sites, the timing, extent and method of the remedial actions which may be required, and the determination of our liability in proportion to other responsible parties.

Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities for expenditures of a non-capital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Substantially all amounts accrued are expected to be paid out over the next 15 years. The level of future expenditures for environmental remediation obligations is impossible to determine with any degree of reliability.

We have accrued environmental remediation obligations of $6,947 ($1,307 accrued liability and $5,640 non-current liability) at September 30, 2014 and December 31, 2013.

(12) Subsequent Event

Distribution Declared

On October 27, 2014, the board of directors of the General Partner declared a cash distribution to our common unitholders of approximately $63,760, or $1.02 per common unit. The cash distribution will be paid on November 28, 2014 to unitholders of record at the close of business on November 10, 2014.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

References in this report to the "Partnership," "Alon," "we," "our," "us" or like terms, refer to Alon USA Partners, LP and its consolidated subsidiaries. Unless the context otherwise requires, references in this report to "Alon Energy" refers to Alon USA Energy, Inc. and any of its consolidated subsidiaries other than the Partnership, its subsidiaries and its general partner.

The following discussion of our financial condition and results of operations should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2013.

Forward-Looking Statements

Certain statements contained in this report and other materials we file with the SEC, or in other written or oral statements made by us, other than statements of historical fact, are "forward-looking statements" as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements relate to matters such as our industry, business strategy, goals and expectations concerning our market position, future operations, margins, profitability, capital expenditures, liquidity and capital resources and other financial and operating information. We have used the words "anticipate," "assume," "believe," "budget," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potent "project," "will," "future" and similar terms and phrases to identify forward-looking statements.

Forward-looking statements reflect our current expectations of future events, results or outcomes. These expectations may or may not be realized. Some of these expectations may be based upon assumptions or judgments that prove to be incorrect. In addition, our business and operations involve numerous risks and uncertainties, many of which are beyond our control, which could result in our expectations not being realized or otherwise materially affect our financial condition, results of operations and cash flows.

Actual events, results and outcomes may differ materially from our expectations due to a variety of factors. Although it is not possible to identify all of these factors, they include, among others, the following:

- changes in general economic conditions and capital markets;
- changes in the underlying demand for our products;
- the availability, costs and price volatility of crude oil, other refinery feedstocks and refined products;
- changes in the spread between West Texas Intermediate ("WTI") Cushing crude oil and West Texas Sour ("WTS") crude oil or WTI Midland crude oil;
- changes in the spread between Brent crude oil and WTI Cushing crude oil;
- the effects of transactions involving forward contracts and derivative instruments;
- actions of customers and competitors;
- termination of our Supply and Offtake Agreement with J. Aron & Company ("J. Aron"), under which J. Aron is our largest supplier of crude oil and our largest customer of refined products. Additionally upon termination of the Supply and Offtake Agreement, we are obligated to purchase the crude oil and refined product inventories then owned by J. Aron at then current market prices;
- changes in fuel and utility costs incurred by our refinery;
- disruptions due to equipment interruption, pipeline disruptions or failure at our or third-party facilities;
- the execution of planned capital projects;
- adverse changes in the credit ratings assigned to our trade credit and debt instruments;
- the effects of and cost of compliance with the renewable fuel standards program, including the availability, cost and price volatility of Renewable Identification Numbers;
- the effects and cost of compliance with current and future state and federal environmental, economic, safety and other laws, policies and regulations;
- operating hazards, natural disasters, casualty losses and other matters beyond our control;
- the effect of any national or international financial crisis on our business and financial condition; and
- the other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2013 under the caption "Risk Factors."

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Any one of these factors or a combination of these factors could materially affect our future results of operations and could influence whether any forward-looking statements ultimately prove to be accurate. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statements. We do not intend to update these statements unless we are required by the securities laws to do so.

Company Overview

We are a Delaware limited partnership formed in August 2012 by Alon USA Energy, Inc. (NYSE: ALJ) ("Alon Energy") to own, operate and grow our strategically-located refining and petroleum products marketing business. Our integrated downstream business operates primarily in the South Central and Southwestern regions of the United States. We own and operate a crude oil refinery in Big Spring, Texas with total crude oil throughput capacity of approximately 73,000 barrels per day ("bpd"), which we refer to as our Big Spring refinery. We refine crude oil into finished products, which we market primarily in West and Central Texas, Oklahoma, New Mexico and Arizona through our wholesale distribution network to both Alon Energy's retail convenience stores and other third-party distributors. We distribute fuel products through a product pipeline and terminal network of seven pipelines and five terminals that we own or access through leases or long-term throughput agreements.

Third Quarter Operational and Financial Highlights

Operating income for the third quarter of 2014 was $89.6 million, compared to operating loss of $3.9 million for the same period last year. Our operational and financial highlights for the third quarter of 2014 include the following:

- Big Spring refinery average throughput for the third quarter of 2014 was 74,838 bpd compared to 63,090 bpd for the third quarter of 2013. The increased refinery throughput was due to the completion of both the planned turnaround and the vacuum tower project during the second quarter of 2014 and the impact of unplanned downtime at our refinery during the third quarter of 2013.
- Operating margin at the Big Spring refinery was $19.98 per barrel for the third quarter of 2014 compared to $6.46 per barrel for the same period in 2013. This increase in operating margin was primarily due to a higher Gulf Coast 3/2/1 crack spread as well as a widening of both the WTI Cushing to WTS spread and the WTI Cushing to WTI Midland spread.
- The average Gulf Coast 3/2/1 crack spread was $15.90 per barrel for the third quarter of 2014 compared to $14.23 per barrel for the third quarter of 2013.
- The average WTI Cushing to WTS spread for the third quarter of 2014 was $8.14 per barrel compared to $0.08 per barrel for the same period in 2013. The average WTI Cushing to WTI Midland spread for the third quarter of 2014 was $9.93 per barrel compared to $0.27 per barrel for the same period in 2013.
- During the third quarter of 2014, we paid cash distributions of $8.1 million, or $0.13 per unit, compared to $44.4 million, or $0.71 per unit during the third quarter of 2013.

Major Influences on Results of Operations

Earnings and cash flow are primarily affected by the difference between refined product prices and the prices for crude oil and other feedstocks. These prices depend on numerous factors beyond our control, including the supply of, and demand for, crude oil, gasoline and other refined products which, in turn, depend on, among other factors, changes in domestic and foreign economies, weather conditions, domestic and foreign political affairs, production levels, the availability of imports, the marketing of competitive fuels and government regulation. While our sales and operating revenues fluctuate significantly with movements in crude oil and refined product prices, it is the spread between crude oil and refined product prices, and not necessarily fluctuations in those prices, that affect our earnings.

In order to measure our operating performance, we compare our per barrel refinery operating margin to certain industry benchmarks. We calculate this margin for the Big Spring refinery by dividing the refinery's gross margin by its throughput volumes. Gross margin is the difference between net sales and cost of sales.

We compare our Big Spring refinery operating margin to the Gulf Coast 3/2/1 crack spread, which is intended to approximate the refinery's crude slate and product yield. A Gulf Coast 3/2/1 crack spread is calculated assuming that three barrels of WTI Cushing crude oil are converted, or cracked, into two barrels of Gulf Coast conventional gasoline and one barrel of Gulf Coast ultra-low sulfur diesel.

Our Big Spring refinery is capable of processing substantial volumes of sour crude oil, which has historically cost less than intermediate and sweet crude oils. We measure the cost advantage of refining sour crude oil by calculating the difference

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between the price of WTI Cushing crude oil and the price of WTS, a medium, sour crude oil. We refer to this differential as the WTI Cushing/WTS, or sweet/sour, spread. A widening of the sweet/sour spread can favorably influence the operating margin for our Big Spring refinery. The Big Spring refinery's crude oil input is primarily comprised of WTS and WTI Midland priced crude oil.

In addition, we have been able to capitalize on the oversupply of West Texas crudes in Midland, the largest origination terminal for West Texas crude oil, resulting from increased production in the Permian Basin coupled with infrastructure constraints. Although West Texas crudes are typically transported to Cushing and to the Gulf Coast for sale, current logistical and infrastructure constraints are limiting the ability of Permian Basin producers to transport their production to Cushing and to the Gulf Coast. The resulting oversupply of West Texas crudes at Midland has depressed Midland crude prices and enabled us to obtain an increased portion of our crude supply at discounted prices to Cushing. Moreover, by sourcing West Texas crude oils at Midland, we are able to eliminate the cost of transporting crude to and from Cushing. The WTI Cushing less WTI Midland spread represents the differential between the average per barrel price of WTI Cushing crude oil and the average per barrel price of WTI Midland crude oil. A widening of the WTI Cushing less WTI Midland spread can favorably influence the operating margin for our Big Spring refinery.

Global product prices are influenced by the price of Brent crude which is a global benchmark crude. Global product prices influence product prices in the U.S. As a result, the Big Spring refinery is influenced by the spread between Brent crude and WTI Cushing. The Brent less WTI Cushing spread represents the differential between the average per barrel price of Brent crude oil and the average per barrel price of WTI Cushing crude oil. A widening of the spread between Brent and WTI Cushing can favorably influence the operating margins for our Big Spring refinery.

Our results of operations are also significantly affected by our refinery's operating costs, particularly the cost of natural gas used for fuel and the cost of electricity. Natural gas prices have historically been volatile. Typically, electricity prices fluctuate with natural gas prices.

Demand for gasoline products is generally higher during summer months than during winter months due to seasonal increases in highway traffic. As a result, our operating results for the first and fourth calendar quarters are generally lower than those for the second and third calendar quarters. The effects of seasonal demand for gasoline are partially offset by seasonality in demand for diesel, which in our region is generally higher in winter months as east-west trucking traffic moves south to avoid winter conditions on northern routes.

Safety, reliability and the environmental performance of our refinery is critical to our financial performance. The financial impact of planned downtime, such as a turnaround or major maintenance project, is mitigated through a diligent planning process that considers expectations for product availability, margin environment and the availability of resources to perform the required maintenance.

The nature of our business requires us to maintain substantial quantities of crude oil and refined product inventories. Crude oil and refined products are commodities, and we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market value under the LIFO inventory valuation methodology, price fluctuations generally have little effect on our financial results.

Factors Affecting Comparability

Our financial condition and operating results over the three and nine months ended September 30, 2014 and 2013 have been influenced by the following factors which are fundamental to understanding comparisons of our period-to-period financial performance.

Maintenance and Turnaround Impact on Crude Oil Throughput

During the nine months ended September 30, 2014, we completed both the planned turnaround and vacuum tower project at the Big Spring refinery, which reduced our refinery throughput. However, these events had a positive impact on the refinery throughput during the three months ended September 30, 2014.

During the nine months ended September 30, 2013, the Big Spring refinery was impacted by an unplanned first quarter shut down to perform maintenance on the crude unit vacuum tower as well as unplanned downtime in the third quarter.

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Results of Operations

The period-to-period comparisons of our results of operations have been prepared using the historical periods included in our consolidated financial statements. We refer to our financial statement line items in the explanation of our period-to-period changes in results of operations. Below are general definitions of what those line items include and represent.

Net sales. Net sales consist principally of sales of refined petroleum products and are mainly affected by refined product prices, changes to the product mix and volume changes caused by operations. Product mix refers to the percentage of production represented by higher value motor fuels, such as gasoline, rather than lower value finished products.

Cost of sales. Cost of sales includes principally crude oil, blending materials, other raw materials and transportation costs. Cost of sales excludes depreciation and amortization, which is presented separately in the consolidated statements of operations.

Direct operating expenses. Direct operating expenses include costs associated with the actual operations of the refinery, such as energy and utility costs, routine maintenance, labor, insurance and environmental compliance costs. All operating costs associated with our crude oil and product pipelines are considered to be transportation costs and are reflected in cost of sales in the consolidated statements of operations.

Selling, general and administrative expenses. Selling, general and administrative expenses, or SG&A, primarily include corporate overhead costs and marketing expenses. These costs also include actual costs incurred by Alon Energy and allocated to us.

Depreciation and amortization. Depreciation and amortization represents an allocation to expense within the consolidated statements of operations of the carrying value of capital assets. The value is allocated based on the straight-line method over the estimated useful life of the related asset. Depreciation and amortization also includes deferred turnaround and catalyst replacement costs. Turnaround and catalyst replacement costs are currently deferred and amortized on a straight-line basis beginning the month after the completion of the turnaround and ending immediately prior to the next scheduled turnaround.

Operating income (loss). Operating income (loss) represents our net sales less our total operating costs and expenses.

Interest expense. Interest expense includes interest expense, letters of credit, financing costs associated with crude oil purchases, financing fees, and amortization of both original issuance discount and deferred debt issuance costs but excludes capitalized interest.

ALON USA PARTNERS, LP AND SUBSIDIARIES CONSOLIDATED

Summary Financial Tables. The following tables provide summary financial data and selected key operating statistics for the three and nine months ended September 30, 2014 and 2013. The following data should be read in conjunction with our consolidated financial statements and the notes thereto included elsewhere in this Form 10-Q. All information in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” except for Balance Sheet data as of December 31, 2013 is unaudited.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(dollars in thousands, except per unit data, per barrel data and pricing statistics)			
STATEMENTS OF OPERATIONS DATA:				
Net sales (1)	$838,882	$881,902	$2,421,194	$2,551,763
Operating costs and expenses:				
Cost of sales	701,331	844,423	2,125,775	2,261,948
Direct operating expenses	25,723	26,281	79,816	84,017
Selling, general and administrative expenses	8,353	4,134	19,505	16,864
Depreciation and amortization	13,852	10,975	33,427	34,282
Total operating costs and expenses	749,259	885,813	2,258,523	2,397,111
Loss on disposition of assets	—	(21)	—	(21)
Operating income (loss)	89,623	(3,932)	162,671	154,631
Interest expense	(11,584)	(12,127)	(34,477)	(30,489)
Other income, net	14	—	627	18
Income (loss) before state income tax expense	78,053	(16,059)	128,821	124,160
State income tax expense	1,060	61	1,785	1,434
Net income (loss)	$76,993	$(16,120)	$127,036	$122,726
Earnings (loss) per unit	$1.23	$(0.26)	$2.03	$1.96
Weighted average common units outstanding (in thousands)	62,507	62,502	62,505	62,502
Cash distribution per unit	$0.13	$0.71	$1.00	$2.76
CASH FLOW DATA:				
Net cash provided by (used in):				
Operating activities	$94,142	$6,476	$139,374	$159,719
Investing activities	(26,195)	(7,682)	(63,081)	(21,658)
Financing activities	(33,751)	34,998	(114,581)	(143,586)
OTHER DATA:				
Adjusted EBITDA (2)	$103,489	$7,064	$196,725	$188,952
Capital expenditures	2,492	7,477	13,931	16,634
Capital expenditures for turnarounds and catalysts	23,703	205	49,150	5,024
KEY OPERATING STATISTICS:				
Per barrel of throughput:				
Refinery operating margin (3)	$19.98	$6.46	$17.35	$16.35
Refinery direct operating expense (4)	3.74	4.53	4.69	4.74
PRICING STATISTICS:				
Crack spreads (per barrel):				
Gulf Coast 3/2/1	$15.90	$14.23	$16.37	$21.21
WTI Cushing crude oil (per barrel)	$97.55	$105.82	$99.74	$98.14
Crude oil differentials (per barrel):				
WTI Cushing less WTI Midland	$9.93	$0.27	$7.31	$2.69

WTI Cushing less WTS	8.14	0.08	6.58	3.91
Brent less WTI Cushing	5.13	5.91	8.52	13.25
Product price (dollars per gallon):				
Gulf Coast unleaded gasoline	$2.65	$2.78	$2.71	$2.77
Gulf Coast ultra-low sulfur diesel	2.80	3.02	2.88	2.99
Natural gas (per MMBtu)	3.95	3.56	4.41	3.69

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	September 30, 2014	December 31, 2013
BALANCE SHEET DATA (end of period):	(dollars in thousands)	
Cash and cash equivalents	$115,295	$153,583
Working capital	10,796	18,007
Total assets	842,435	849,924
Total debt	292,858	344,322
Total debt less cash and cash equivalents	177,563	190,739
Total partners' equity	210,028	145,442

THROUGHPUT AND PRODUCTION DATA:	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2014		2013		2014		2013	
	bpd	%	bpd	%	bpd	%	bpd	%
Refinery throughput:								
WTS crude	37,566	50.2	36,340	57.6	28,524	45.7	45,029	69.3
WTI crude	34,633	46.3	25,169	39.9	31,330	50.2	18,016	27.8
Blendstocks	2,639	3.5	1,581	2.5	2,528	4.1	1,865	2.9
Total refinery throughput (5)	74,838	100.0	63,090	100.0	62,382	100.0	64,910	100.0
Refinery production:								
Gasoline	36,842	49.0	30,861	49.2	30,207	48.4	31,905	49.4
Diesel/jet	28,857	38.4	20,999	33.4	21,964	35.2	21,688	33.5
Asphalt	3,052	4.1	3,312	5.3	2,705	4.3	3,708	5.7
Petrochemicals	4,305	5.7	3,599	5.7	3,514	5.6	3,984	6.2
Other	2,078	2.8	4,045	6.4	4,030	6.5	3,371	5.2
Total refinery production (6)	75,134	100.0	62,816	100.0	62,420	100.0	64,656	100.0
Refinery utilization (7)		98.9 %		87.9 %		97.0 %		93.8 %

(1) Includes sales to related parties of $156,131 and $164,338 for the three months and $447,314 and $462,280 for the nine months ended September 30, 2014 and 2013, respectively.

(2) Adjusted EBITDA represents earnings before state income tax expense, interest expense, depreciation and amortization and loss on disposition of assets. Adjusted EBITDA is not a recognized measurement under GAAP; however, the amounts included in Adjusted EBITDA are derived from amounts included in our consolidated financial statements. Our management believes that the presentation of Adjusted EBITDA is useful to investors because it is frequently used by securities analysts, investors, and other interested parties in the evaluation of companies in our industry. In addition, our management believes that Adjusted EBITDA is useful in evaluating our operating performance compared to that of other companies in our industry because the calculation of Adjusted EBITDA generally eliminates the effects of state income tax expense, interest expense, loss on disposition of assets and the accounting effects of capital expenditures and acquisitions, items that may vary for different companies for reasons unrelated to overall operating performance.

Adjusted EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Some of these limitations are:

- Adjusted EBITDA does not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- Adjusted EBITDA does not reflect the interest expense or the cash requirements necessary to service interest or principal payments on our debt;
- Adjusted EBITDA does not reflect changes in or cash requirements for our working capital needs; and
-

Our calculation of Adjusted EBITDA may differ from EBITDA calculations of other companies in our industry, limiting its usefulness as a comparative measure.

Because of these limitations, Adjusted EBITDA should not be considered a measure of discretionary cash available to us to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using Adjusted EBITDA only supplementally.

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The following table reconciles net income (loss) to Adjusted EBITDA for the three and nine months ended September 30, 2014 and 2013:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2014	2013	2014	2013
	(dollars in thousands)			
Net income (loss)	$76,993	$(16,120)	$127,036	$122,726
State income tax expense	1,060	61	1,785	1,434
Interest expense	11,584	12,127	34,477	30,489
Depreciation and amortization	13,852	10,975	33,427	34,282
Loss on disposition of assets	—	21	—	21
Adjusted EBITDA	$103,489	$7,064	$196,725	$188,952

(3) Refinery operating margin is a per barrel measurement calculated by dividing the margin between net sales and cost of sales by the refinery's throughput volumes. Industry-wide refining results are driven and measured by the margins between refined product prices and the prices for crude oil, which are referred to as crack spreads. We compare our refinery operating margin to these crack spreads to assess our operating performance relative to other participants in our industry.

(4) Refinery direct operating expense is a per barrel measurement calculated by dividing direct operating expenses by total throughput volumes.

(5) Total refinery throughput represents the total barrels per day of crude oil and blendstock inputs in the refinery production process.

(6) Total refinery production represents the barrels per day of various refined products produced from processing crude and other refinery feedstocks through the crude units and other conversion units.

(7) Refinery utilization represents average daily crude oil throughput divided by crude oil capacity, excluding planned periods of downtime for maintenance and turnarounds.

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Three Months Ended September 30, 2014 Compared to the Three Months Ended September 30, 2013

Net Sales. Net sales for the three months ended September 30, 2014 were $838.9 million, compared to $881.9 million for the three months ended September 30, 2013, a decrease of $43.0 million. This decrease was due to lower refined product prices, partially offset by higher refinery throughput during the three months ended September 30, 2014, compared to the same period last year. Refinery average throughput for the three months ended September 30, 2014 was 74,838 bpd, compared to 63,090 bpd for the three months ended September 30, 2013, an increase of 18.6%. The increased refinery throughput was due to the completion of both the planned turnaround and the vacuum tower project during the second quarter of 2014 and the impact of unplanned downtime at our refinery during the third quarter of 2013. The average per gallon price of Gulf Coast gasoline for the three months ended September 30, 2014 decreased $0.13, or 4.7%, to $2.65, compared to $2.78 for the three months ended September 30, 2013. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the three months ended September 30, 2014 decreased $0.22, or 7.3%, to $2.80, compared to $3.02 for the three months ended September 30, 2013.

Cost of Sales. Cost of sales for the three months ended September 30, 2014 were $701.3 million, compared to $844.4 million for the three months ended September 30, 2013, a decrease of $143.1 million. This decrease was primarily due to reduced crude oil prices, partially offset by higher refinery throughput. The average price of WTI Cushing decreased 7.8% to $97.55 per barrel for the three months ended September 30, 2014 from $105.82 per barrel for the three months ended September 30, 2013. The WTI Cushing to WTS spread widened for the three months ended September 30, 2014 to $8.14 per barrel compared to $0.08 per barrel for the three months ended September 30, 2013. The WTI Cushing to WTI Midland spread widened to $9.93 per barrel for the three months ended September 30, 2014, compared to $0.27 per barrel for the three months ended September 30, 2013.

Direct Operating Expenses. Direct operating expenses for the three months ended September 30, 2014 were $25.7 million, compared to $26.3 million for the three months ended September 30, 2013, a decrease of $0.6 million, or 2.3%. This decrease was primarily due to lower insurance costs, partially offset by higher utility costs for the three months ended September 30, 2014.

Selling, General and Administrative Expenses. SG&A expenses for the three months ended September 30, 2014 were $8.4 million, compared to $4.1 million for the three months ended September 30, 2013, an increase of $4.3 million, primarily due to higher employee related costs.

Depreciation and Amortization. Depreciation and amortization for the three months ended September 30, 2014 was $13.9 million, compared to $11.0 million for the three months ended September 30, 2013, an increase of $2.9 million, or 26.4%. This increase was primarily due to increased amortization of turnaround and catalyst replacement costs during the three months ended September 30, 2014 resulting from the completion of the planned turnaround during the second quarter of 2014.

Operating Income (Loss). Operating income for the three months ended September 30, 2014 was $89.6 million, compared to operating loss of $3.9 million for the three months ended September 30, 2013, an increase of $93.5 million. This increase was primarily due to higher refinery operating margin and higher refinery throughput. Refinery operating margin was $19.98 per barrel for the three months ended September 30, 2014, compared to $6.46 per barrel for the three months ended September 30, 2013. This increase in operating margin was primarily due to a higher Gulf Coast 3/2/1 crack spread as well as a widening of both the WTI Cushing to WTS spread and the WTI Cushing to WTI Midland spread. The average Gulf Coast 3/2/1 crack spread increased to $15.90 per barrel for the three months ended September 30, 2014, compared to $14.23 per barrel for the three months ended September 30, 2013.

Interest Expense. Interest expense for the three months ended September 30, 2014 was $11.6 million, compared to $12.1 million for the three months ended September 30, 2013, a decrease of $0.5 million.

Net Income (loss). Net income for the three months ended September 30, 2014 was $77.0 million, compared to net loss of $16.1 million for the three months ended September 30, 2013, an increase of $93.1 million. This increase was attributable to the factors discussed above.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Net Sales. Net sales for the nine months ended September 30, 2014 were $2,421.2 million, compared to $2,551.8 million for the nine months ended September 30, 2013, a decrease of $130.6 million. This decrease was primarily due to lower refinery throughput and lower refined product prices, partially offset by increased sales of purchased products. Refinery average throughput for the nine months ended September 30, 2014 was 62,382 bpd compared to 64,910 bpd for the nine months ended September 30, 2013, a decrease of 3.9%. During the nine months ended September 30, 2014, we completed both the planned turnaround and the vacuum tower project at our refinery, which resulted in reduced refinery throughput during the period.

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The average per gallon price of Gulf Coast gasoline for the nine months ended September 30, 2014 decreased $0.06, or 2.2%, to $2.71, compared to $2.77 for the nine months ended September 30, 2013. The average per gallon price of Gulf Coast ultra-low sulfur diesel for the nine months ended September 30, 2014 decreased $0.11, or 3.7%, to $2.88, compared to $2.99 for the nine months ended September 30, 2013.

Cost of Sales. Cost of sales for the nine months ended September 30, 2014 were $2,125.8 million, compared to $2,261.9 million for the nine months ended September 30, 2013, a decrease of $136.1 million. This decrease was primarily due to reduced refinery throughput and a decrease in crude oil prices at our refinery, partially offset by increased products purchased to meet contractual obligations during the planned turnaround. The average price of WTI Cushing increased 1.6% to $99.74 per barrel for the nine months ended September 30, 2014 from $98.14 per barrel for the nine months ended September 30, 2013. The WTI Cushing to WTS spread widened 68.3%, to $6.58 per barrel for the nine months ended September 30, 2014, compared to $3.91 per barrel for the nine months ended September 30, 2013. The WTI Cushing to WTI Midland spread widened to $7.31 per barrel for the nine months ended September 30, 2014, compared to $2.69 per barrel for the nine months ended September 30, 2013.

Direct Operating Expenses. Direct operating expenses for the nine months ended September 30, 2014 were $79.8 million, compared to $84.0 million for the nine months ended September 30, 2013, a decrease of $4.2 million, or 5.0%. This decrease was primarily due to lower major maintenance and insurance costs, partially offset by higher utility costs for the nine months ended September 30, 2014.

Selling, General and Administrative Expenses. SG&A expenses for the nine months ended September 30, 2014 were $19.5 million, compared to $16.9 million for the nine months ended September 30, 2013, an increase of $2.6 million. This increase was primarily due to higher employee related costs for the nine months ended September 30, 2014.

Depreciation and Amortization. Depreciation and amortization for the nine months ended September 30, 2014 was $33.4 million, compared to $34.3 million for the nine months ended September 30, 2013, a decrease of $0.9 million.

Operating Income. Operating income for the nine months ended September 30, 2014 was $162.7 million, compared to $154.6 million for the nine months ended September 30, 2013, an increase of $8.1 million. This increase was primarily due to higher refinery operating margins, partially offset by lower refinery throughput. Refinery operating margin was $17.35 per barrel for the nine months ended September 30, 2014, compared to $16.35 per barrel for the nine months ended September 30, 2013. This increase in operating margin was primarily due to a widening of both the WTI Cushing to WTS spread and the WTI Cushing to WTI Midland spread, partially offset by a lower Gulf Coast 3/2/1 crack spread. The average Gulf Coast 3/2/1 crack spread decreased 22.8% to $16.37 per barrel for the nine months ended September 30, 2014, compared to $21.21 per barrel for the nine months ended September 30, 2013, which was primarily influenced by a reduction in the Brent to WTI Cushing spread. The average Brent to WTI Cushing spread for the nine months ended September 30, 2014 was $8.52 per barrel compared to $13.25 per barrel for the nine months ended September 30, 2013.

Interest Expense. Interest expense was $34.5 million for the nine months ended September 30, 2014, compared to interest expense of $30.5 million for the nine months ended September 30, 2013, an increase of $4.0 million. This increase was primarily due to higher financing costs associated with crude oil purchases as a result of a backwardated crude oil market.

Net Income. Net income for the nine months ended September 30, 2014 was $127.0 million, compared to $122.7 million for the nine months ended September 30, 2013, an increase of $4.3 million. This increase was attributable to the factors discussed above.

Liquidity and Capital Resources

Our primary sources of liquidity are cash on hand, cash generated from our operating activities, borrowings under our revolving credit facility, inventory supply and offtake arrangement and other credit lines. Additionally, we have the ability to utilize a $60 million letter of credit facility through Alon Energy for our crude and product purchases.

We have an agreement with J. Aron for the supply of crude oil that supports the operations of the Big Spring refinery. This arrangement substantially reduces our physical inventories and the associated need to issue letters of credit to support crude oil purchases. In addition, the structure allows us to acquire crude oil without the constraints of a maximum facility size during periods of high crude oil prices.

We believe that the aforementioned sources of funds and other sources of capital available to us will be sufficient to satisfy the anticipated cash requirements associated with our existing operations for at least the next twelve months. However, future capital expenditures and other cash requirements could be higher than we currently expect as a result of various factors. Additionally, our ability to generate sufficient cash from our operating activities depends on our future performance, which is subject to general economic, political, financial, competitive, and other factors beyond our control.

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Cash Flows

The following table sets forth our consolidated cash flows for the nine months ended September 30, 2014 and 2013:

	For the Nine Months Ended September 30,	
	2014	2013
	(dollars in thousands)	
Cash provided by (used in):		
Operating activities	$139,374	$159,719
Investing activities	(63,081)	(21,658)
Financing activities	(114,581)	(143,586)
Net decrease in cash and cash equivalents	$(38,288)	$(5,525)

Cash Flows Provided by Operating Activities

Net cash provided by operating activities was $139.4 million during the nine months ended September 30, 2014 compared to $159.7 million during the nine months ended September 30, 2013. The reduction in net cash provided by operating activities of $20.3 million was primarily due to reduced cash provided by accounts payable and accrued liabilities of $38.4 million and increased cash used on prepaid expenses and other current assets of $6.7 million, partially offset by higher net income after adjusting for non-cash items of $3.5 million, reduced cash used on inventories of $9.5 million and increased cash collected on accounts receivable of $9.2 million.

Cash Flows Used In Investing Activities

Net cash used in investing activities was $63.1 million during the nine months ended September 30, 2014 compared to $21.7 million during the nine months ended September 30, 2013. The increase in net cash used in investing activities of $41.4 million was primarily due to an increase in capital expenditures and capital expenditures for turnarounds and catalysts associated with the planned turnaround completed during the second quarter of 2014.

Cash Flows Used In Financing Activities

Net cash used in financing activities was $114.6 million during the nine months ended September 30, 2014 compared to $143.6 million during the nine months ended September 30, 2013. The reduction in net cash used in financing activities of $29.0 million was primarily attributable to lower distributions to unitholders of $110.0 million, partially offset by increased payments on our revolving credit facility of $81.0 million.

Indebtedness

Revolving Credit Facility. We have a $240.0 million revolving credit facility that can be used both for borrowings and the issuance of letters of credit. Borrowings of $50.0 million and $100.0 million and letters of credit of $90.7 million and $109.8 million were outstanding under this facility at September 30, 2014 and December 31, 2013, respectively.

Capital Spending

Each year the Board of Directors of our General Partner approves capital projects, including sustaining maintenance, regulatory and planned turnaround projects that our management is authorized to undertake in our annual capital budget. Additionally, at times when conditions warrant or as new opportunities arise, growth and profit improvement projects may be approved. Our total capital expenditure plan, including expenditures for catalysts and turnarounds, for 2014 is $67.0 million. Approximately $63.1 million has been spent during the nine months ended September 30, 2014.

Contractual Obligations and Commercial Commitments

There have been no material changes outside the ordinary course of business from our contractual obligations and commercial commitments detailed in our Annual Report on Form 10-K for the year ended December 31, 2013.

Off-Balance Sheet Arrangements

We have no material off-balance sheet arrangements.

Critical Accounting Policies

We prepare our consolidated financial statements in conformity with GAAP. In order to apply these principles, we must make judgments, assumptions and estimates based on the best available information at the time. Actual results may differ based on the accuracy of the information utilized and subsequent events, some of which we may have little or no control over.

Our critical accounting policies are described under the caption “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies” in our Annual Report on Form 10-K for the year ended December 31, 2013. Certain critical accounting policies that materially affect the amounts recorded in our consolidated financial statements are the use of the LIFO method for valuing certain inventories and the deferral and subsequent amortization of costs associated with major turnarounds and catalysts replacements. No significant changes to these accounting policies have occurred subsequent to December 31, 2013.

New Accounting Standards and Disclosures

New accounting standards, if any, are disclosed in Note (1) Basis of Presentation included in the consolidated financial statements included in Item 1 of this report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Changes in commodity prices, purchased fuel prices and interest rates are our primary sources of market risk. Alon Energy's risk management committee oversees all activities associated with the identification, assessment and management of our market risk exposure.

Commodity Price Risk

We are exposed to market risks related to the volatility of crude oil and refined product prices, as well as volatility in the price of natural gas used in our refinery operations. Our financial results can be affected significantly by fluctuations in these prices, which depend on many factors, including demand for crude oil, gasoline and other refined products, changes in the economy, worldwide production levels, worldwide inventory levels and governmental regulatory initiatives. Alon Energy's risk management strategy identifies circumstances in which we may utilize the commodity futures market to manage risk associated with these price fluctuations.

In order to manage the uncertainty relating to inventory price volatility, we have consistently applied a policy of maintaining inventories at or below a targeted operating level. In the past, circumstances have occurred, such as timing of crude oil cargo deliveries, turnaround schedules or shifts in market demand that have resulted in variances between our actual inventory level and our desired target level. Upon the review and approval of Alon Energy's risk management committee, we may utilize the commodity futures market to manage these anticipated inventory variances.

We maintain inventories of crude oil, refined products and blendstocks, the values of which are subject to wide fluctuations in market prices driven by world economic conditions, regional and global inventory levels and seasonal conditions. As of September 30, 2014, we held 0.7 million barrels of crude oil and refined product inventories valued under the LIFO valuation method. Market value exceeded carrying value of LIFO costs by $17.7 million. We refer to this excess as our LIFO reserve. If the market value of these inventories had been $1.00 per barrel lower, our LIFO reserve would have been reduced by $0.7 million.

All commodity derivative contracts are recorded at fair value and any changes in fair value between periods is recorded in the profit and loss section of our consolidated financial statements. "Forwards" represent physical trades for which pricing and quantities have been set, but the physical product delivery has not occurred by the end of the reporting period. "Futures" represent trades which have been executed on the New York Mercantile Exchange which have not been closed or settled at the end of the reporting period. A "long" represents an obligation to purchase product and a "short" represents an obligation to sell product.

The following table provides information about our commodity derivative contracts as of September 30, 2014:

Description of Activity	Contract Volume (barrels)	Wtd Avg Purchase Price/BBL	Wtd Avg Sales Price/BBL	Contract Value	Market Value	Gain (Loss)
				(in thousands)		
Forwards-long (Crude)	47,314	$82.93	$—	$3,924	$3,921	$(3)
Forwards-long (Gasoline)	328,723	107.54	—	35,349	33,235	(2,114)
Forwards-long (Distillate)	108,472	113.06	—	12,264	12,057	(207)
Forwards-long (Jet)	27,864	117.16	—	3,264	3,102	(162)
Forwards-long (Slurry)	456	84.91		39	37	(2)
Forwards-long (Catfeed)	11,799	105.29	—	1,242	1,180	(62)
Forwards-short (Slop)	(908)	—	82.99	(75)	(73)	2
Forwards-short (Propane)	(50,000)	—	42.42	(2,121)	(1,968)	153
Futures-short (Crude)	(101,000)	—	91.75	(9,267)	(9,207)	60
Futures-short (Gasoline)	(350,000)	—	105.27	(36,846)	(35,829)	1,017
Futures-short (Distillate)	(121,000)	—	116.32	(14,075)	(13,474)	601

Interest Rate Risk

As of September 30, 2014, our outstanding debt balance of $295.6 million, excluding discounts, was subject to floating interest rates, of which $245.6 million was charged interest at the Eurodollar rate (with a floor of 1.25%) plus a margin of 8.00% and $50.0 million was charged interest at the Eurodollar rate plus 3.5%, subject to a minimum

interest rate of 4.0%.
An increase of 1% in the Eurodollar rate on our indebtedness would result in an increase in our interest expense of approximately $0.3 million per year.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure controls and procedures

Our management has evaluated, with the participation of our principal executive and principal financial officers, the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 as amended (the “Exchange Act”)) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission’s rules and forms including, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosures.

Changes in internal control over financial reporting

There has been no change in our internal control over financial reporting (as described in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. We are transitioning our assessment of our internal control effectiveness over financial reporting from the criteria outlined by the 1992 framework of the Committee of Sponsoring Organizations of the Treadway Commission to its 2013 framework. We expect to complete this transition during 2014.

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PART II. OTHER INFORMATION

ITEM 6. EXHIBITS

Exhibit Number	Description of Exhibit
31.1	Certifications of Chief Executive Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002.
31.2	Certifications of Chief Financial Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002.
32.1	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002.
101	The following financial information from Alon USA Partners, LP's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Cash Flows and (iv) Notes to the Consolidated Financial Statements.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Alon USA Partners, LP
	By: Alon USA Partners GP, LLC its general partner
Date: October 31, 2014	By: /s/ David Wiessman David Wiessman Executive Chairman of the Board
Date: October 31, 2014	By: /s/ Paul Eisman Paul Eisman President, Chief Executive Officer and Director
Date: October 31, 2014	By: /s/ Shai Even Shai Even Senior Vice President and Chief Financial Officer (Principal Accounting Officer)

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