ORMAT TECHNOLOGIES, INC.
Form 10-Q
November 06, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

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: 001-32347

ORMAT TECHNOLOGIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	**88-0326081**
(State or other jurisdiction of	*(I.R.S. Employer*
incorporation or organization)	*Identification Number)*
6225 Neil Road, Reno, Nevada	**89511-1136**
(Address of principal executive offices)	*(Zip Code)*

(775) 356-9029

(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 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 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. (Check one):

Large accelerated filer	Accelerated filer	Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: As of November 6, 2014, the number of outstanding shares of common stock, par value $0.001 per share, was 45,530,627.

ORMAT TECHNOLOGIES, INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2014

Certain Definitions

Unless the context otherwise requires, all references in this quarterly report to "Ormat", "the Company", "we", "us", "our company", "Ormat Technologies" or "our" refer to Ormat Technologies, Inc. and its consolidated subsidiaries.

PART I - FINANCIAL INFORMATION

ITEM 1. ***FINANCIAL STATEMENTS***

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2014	December 31, 2013
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$42,451	$57,354
Restricted cash, cash equivalents and marketable securities (all related to variable interest entities ("VIEs"))	127,452	51,065
Receivables:		
Trade	75,224	95,365
Related entity	506	442
Other	9,165	11,049
Due from Parent	970	382
Inventories	17,337	22,289
Costs and estimated earnings in excess of billings on uncompleted contracts	14,784	21,217
Deferred income taxes	2,613	523
Prepaid expenses and other	36,879	29,654
Total current assets	327,381	289,340
Unconsolidated investments	1,339	7,076
Deposits and other	21,679	22,114
Deferred income taxes	—	891
Deferred charges	35,399	36,738
Property, plant and equipment, net ($1,378,484 and $1,381,083 related to VIEs, respectively)	1,459,316	1,452,336
Construction-in-process ($143,548 and $136,947 related to VIEs, respectively)	268,349	288,827
Deferred financing and lease costs, net	28,969	30,178
Intangible assets, net	29,481	31,933
Total assets	$2,171,913	$2,159,433
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$78,411	$98,047
Billings in excess of costs and estimated earnings on uncompleted contracts	45,310	7,903
Current portion of long-term debt:		

Limited and non-recourse (all related to VIEs):		
Senior secured notes	31,211	31,137
Other loans	17,995	20,377
Full recourse	24,116	28,875
Total current liabilities	197,043	186,339
Long-term debt, net of current portion:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	379,036	270,310
Other loans	269,123	311,078
Full recourse:		
Senior unsecured bonds (plus unamortized premium based upon 7% of $898)	250,366	250,596
Other loans	40,298	53,467
Revolving credit lines with banks	28,100	112,017
Liability associated with sale of tax benefits	44,757	60,985
Deferred lease income	61,294	63,496
Deferred income taxes	67,328	55,035
Liability for unrecognized tax benefits	5,606	4,950
Liabilities for severance pay	21,984	23,841
Asset retirement obligation	19,801	18,679
Other long-term liabilities	3,633	3,529
Total liabilities	1,388,369	1,414,322
Commitments and contingencies (Note 10)		
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 45,530,627 and 45,460,653 shares issued and outstanding as of September 30, 2014 and December 31, 2013, respectively	46	46
Additional paid-in capital	740,651	735,295
Retained earnings (accumulated deficit)	36,835	(3,088)
Accumulated other comprehensive income (loss)	(5,710)	487
	771,822	732,740
Noncontrolling interest	11,722	12,371
Total equity	783,544	745,111
Total liabilities and equity	$2,171,913	$2,159,433

The accompanying notes are an integral part of the condensed consolidated financial statements

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND

COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In thousands, except per share data)		(In thousands, except per share data)	
Revenues:				
Electricity	$102,506	$88,994	$289,015	$245,005
Product	37,736	41,755	121,266	157,329
Total revenues	140,242	130,749	410,281	402,334
Cost of revenues:				
Electricity	61,727	61,356	186,083	175,085
Product	23,040	29,637	75,307	110,335
Total cost of revenues	84,767	90,993	261,390	285,420
Gross margin	55,475	39,756	148,891	116,914
Operating expenses:				
Research and development expenses	250	838	395	3,446
Selling and marketing expenses	4,258	2,575	10,853	17,861
General and administrative expenses	7,179	6,546	20,847	20,264
Write-off of unsuccessful exploration activities	—	—	8,107	—
Operating income	43,788	29,797	108,689	75,343
Other income (expense):				
Interest income	35	742	236	870
Interest expense, net	(22,494)	(18,459)	(65,084)	(51,826)
Foreign currency translation and transaction gains (losses)	(2,946)	1,258	(3,639)	3,844
Income attributable to sale of tax benefits	5,487	5,027	18,334	14,342
Gain from sale of property, plant and equipment	—	—	7,628	—
Other non-operating income, net	243	137	649	1,583
Income before income taxes and equity in losses of investees	24,113	18,502	66,813	44,156
Income tax provision	(6,444)	(5,201)	(17,731)	(15,028)
Equity in losses of investees	(899)	(158)	(1,210)	(149)
Income from continuing operations	16,770	13,143	47,872	28,979
Discontinued operations:				
Income from discontinued operations (including gain on disposal of $0, $0, $0 and $3,646, respectively)	—	—	—	5,311
Income tax provision	—	—	—	(614)
Total income from discontinued operations	—	—	—	4,697

Net income	16,770	13,143	47,872	33,676
Net income attributable to noncontrolling interest	(256)	(193)	(670)	(600)
Net income attributable to the Company's stockholders	$16,514	$12,950	$47,202	$33,076
Comprehensive income:				
Net income	16,770	13,143	47,872	33,676
Other comprehensive income (loss), net of related taxes:				
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment	(1,069)	—	(5,157)	—
Loss in respect of derivative instruments designated for cash flow hedge	(933)	—	(933)	—
Amortization of unrealized gains or losses in respect of derivative instruments designated for cash flow hedge	(35)	(40)	(107)	(124)
Comprehensive income	14,733	13,103	41,675	33,552
Comprehensive income attributable to noncontrolling interest	(256)	(193)	(670)	(600)
Comprehensive income attributable to the Company's stockholders	$14,477	$12,910	$41,005	$32,952
Earnings per share attributable to the Company's stockholders				
Basic:				
Income from continuing operations	$0.37	$0.29	$1.04	$0.62
Discontinued operations	—	—	—	0.10
Net income	$0.37	$0.29	$1.04	$0.72
Diluted:				
Income from continuing operations	$0.36	$0.28	$1.03	$0.62
Discontinued operations	—	—	—	0.10
Net income	$0.36	$0.28	$1.03	$0.72
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:				
Basic	45,690	45,438	45,594	45,433
Diluted	46,102	45,494	45,917	45,454
Dividend per share declared	$0.05	$0.04	$0.16	$0.04

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(Unaudited)

	The Company's Stockholders' Equity							
			Additional	Retained Earnings	Accumulated Other Income			
	Common Stock		Paid-in	(Accumulated	Comprehensive		Noncontrolling	Total
	Shares	Amount	Capital	Deficit)	(Loss)	Total	Interest	Equity
	(In thousands, except per share data)							
Balance at December 31, 2012, as revised	45,431	$ 46	$ 732,140	$ (44,326)	$ 651	$ 688,511	$ 7,096	$ 695,607
Stock-based compensation	—	—	4,548	—	—	4,548	—	4,548
Exercise of options by employees and directors	23	—	437	—	—	437	—	437
Cash paid to non-controlling interest	—	—	—	—	—	—	(509)	(509)
Cash dividend paid, $0.04 per share	—	—	—	(1,816)	—	(1,816)	—	(1,816)
Increase in noncontrolling interest due to sale of equity interest in ORTP LLC	—	—	—	—	—	—	5,151	5,151
Net income	—	—	—	33,076	—	33,076	600	33,676
Other comprehensive loss, net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $52)	—	—	—	—	(124)	(124)	—	(124)
Balance at September 30, 2013	45,454	$ 46	$ 737,125	$ (13,066)	$ 527	$ 724,632	$ 12,338	$ 736,970
Balance at December 31, 2013	45,461	$ 46	$ 735,295	$ (3,088)	$ 487	$ 732,740	$ 12,371	$ 745,111
Stock-based compensation	—	—	4,308	—	—	4,308	—	4,308
Exercise of options by employees and directors	70	—	889	—	—	889	—	889

Cash paid to noncontrolling interest	—	—	—	—	—	—	(589)	(589)
Cash dividend declared, $0.16 per share	—	—	—	(7,279)	—	(7,279)	—	(7,279)
Acquisition of noncontrolling interest in Crump	—	—	159	—	—	159	(987)	(828)
Increase in noncontrolling interest	—	—	—	—	—	—	257	257
Net income	—	—	—	47,202	—	47,202	670	47,872
Other comprehensive income, net of related taxes:								
Loss in respect of derivative instruments designated for cash flow hedge (net of related tax of $572)	—	—	—	—	(933)	(933)	—	(933)
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment (net of related tax of $0)	—	—	—	—	(5,157)	(5,157)	—	(5,157)
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $44)	—	—	—	—	(107)	(107)	—	(107)
Balance at September 30, 2014	45,531	$ 46	$ 740,651	$ 36,835	$ (5,710)	$ 771,822	$ 11,722	$ 783,544

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

6

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$47,872	$33,676
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	74,836	70,911
Amortization of premium from senior unsecured bonds	(230)	(231)
Accretion of asset retirement obligation	1,122	1,147
Stock-based compensation	4,308	4,548
Amortization of deferred lease income	(2,014)	(2,014)
Income attributable to sale of tax benefits, net of interest expense	(10,130)	(6,621)
Equity in losses of investees	1,210	149
Mark-to-market of derivative instruments	(4,467)	3,487
Write-off of unsuccessful exploration activities	8,107	—
Loss (gain) on severance pay fund asset	798	(399)
Gain on sale of a subsidiary and property, plant and equipment	(7,628)	(3,646)
Deferred income tax provision	13,071	14,235
Liability for unrecognized tax benefits	656	1,598
Deferred lease revenues	(188)	(167)
Other	(181)	(819)
Changes in operating assets and liabilities, net of amounts acquired:		
Receivables	21,624	(23,181)
Costs and estimated earnings in excess of billings on uncompleted contracts	6,433	(26,588)
Inventories	4,952	273
Prepaid expenses and other	(5,163)	(6,175)
Deposits and other	279	4,296
Accounts payable and accrued expenses	(10,868)	(21,449)
Due from/to related entities, net	(64)	(69)
Billings in excess of costs and estimated earnings on uncompleted contracts	37,407	(12,700)
Liabilities for severance pay	(1,857)	1,068
Other long-term liabilities	(527)	959
Due from/to Parent	(588)	(62)
Net cash provided by operating activities	178,770	32,226
Cash flows from investing activities:		
Short-term deposit	—	3,010
Net change in restricted cash and cash equivalents	(76,387)	(7,660)
Cash received from sale of a subsidiary and property, plant and equipment	35,250	7,699
Capital expenditures	(122,587)	(144,637)

Cash grant received from the U.S. Treasury under Section 1603 of the ARRA	27,427	14,685
Investment in unconsolidated companies	(631)	(2,467)
Increase in severance pay fund asset, net of payments made to retired employees	1,493	1,172
Net cash used in investing activities	(135,435)	(128,198)
Cash flows from financing activities:		
Proceeds from long-term loans	140,000	45,000
Proceeds from exercise of options by employees	741	437
Proceeds from the sale of limited liability company interest in ORTP, LLC, net of transaction costs	—	31,376
Payment for acquisition of noncontrolling interest in Crump	(1,490)	—
Purchase of OFC Senior Secured Notes	(12,860)	(11,888)
Proceeds from revolving credit lines with banks	2,400,683	2,170,287
Repayment of revolving credit lines with banks	(2,484,600)	(2,120,605)
Repayments of long-term debt	(80,223)	(37,480)
Cash paid to non-controlling interest	(9,215)	(10,184)
Cash paid for interest rate cap	(1,505)	—
Cash received from non-controlling interest	2,234	—
Deferred debt issuance costs	(4,724)	(348)
Cash dividends paid	(7,279)	(1,816)
Net cash provided by (used in) financing activities	(58,238)	64,779
Net change in cash and cash equivalents	(14,903)	(31,193)
Cash and cash equivalents at beginning of period	57,354	66,628
Cash and cash equivalents at end of period	$42,451	$35,435
Supplemental non-cash investing and financing activities:		
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$(5,221)	$7,744
Accrued liabilities related to financing activities	$—	$(1,347)

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1 — GENERAL AND BASIS OF PRESENTATION

These unaudited condensed consolidated interim financial statements of Ormat Technologies, Inc. and its subsidiaries (collectively, the "Company") have been prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") for interim financial statements. Accordingly, they do not contain all information and notes required by U.S. GAAP for annual financial statements. In the opinion of management, these unaudited condensed consolidated interim financial statements reflect all adjustments, which include normal recurring adjustments, necessary for a fair statement of the Company's consolidated financial position as of September 30, 2014, the consolidated results of operations and comprehensive income for the three and nine-month periods ended September 30, 2014 and 2013 and the consolidated cash flows for the nine-month periods ended September 30, 2014 and 2013.

The financial data and other information disclosed in the notes to the condensed consolidated financial statements related to these periods are unaudited. The results for the three and nine-month periods ended September 30, 2014 are not necessarily indicative of the results to be expected for the year ending December 31, 2014.

These condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in the Company's annual report on Form 10-K for the year ended December 31, 2013. The condensed consolidated balance sheet data as of December 31, 2013 was derived from the audited consolidated financial statements for the year ended December 31, 2013, but does not include all disclosures required by U.S. GAAP.

Dollar amounts, except per share data, in the notes to these financial statements are rounded to the closest $1,000.

Other comprehensive income

For the nine months ended September 30, 2014 and 2013, the Company reclassified $107,000 and $124,000, respectively, from other comprehensive income, of which $173,000 and $200,000, respectively, were recorded to reduce interest expense and $66,000 and $88,000, respectively, were recorded against the income tax provision, in the condensed consolidated statements of operations and comprehensive income. For the three months ended September 30, 2014 and 2013, the Company reclassified $35,000 and $40,000, respectively, from other comprehensive income, of which $57,000 and $76,000, respectively, were recorded to reduce interest expense and $22,000 and $25,000, respectively, were recorded against the income tax provision, in the condensed consolidated statements of operations and comprehensive income.

Termination fee

On March 15, 2013, the Company finalized the agreement with Southern California Edison Company (“Southern California Edison”), by which the G1 and G3 Standard Offer #4 power purchase agreements (“PPAs”) were terminated and a termination fee of $9.0 million was recorded in the first quarter of 2013 in selling and marketing expenses. Under the agreement, the Company will continue to sell power from G2, the third plant of the Mammoth complex, under its existing PPA with Southern California Edison, with the term of the contract extended by an additional six years until early 2027.

Solar project sale

On March 26, 2014, the Company signed an agreement with RET Holdings, LLC to sell the Heber Solar project in Imperial County, California for $35.25 million. The Company received the first payment of $15.0 million during the first quarter of 2014 and the second payment for the remaining $20.25 million was paid in the second quarter of 2014. Due to certain contingencies in the sale agreement, the Company deferred the pre-tax gain of approximately $7.6 million until the contingencies were resolved in the second quarter of 2014.

Write-off of unsuccessful exploration activities

Write-off of unsuccessful activities for the nine months ended September, 30, 2014, was $8.1 million. This represents the write-off of exploration costs related to the Company’s exploration activities in the Wister site in California, which the Company determined in the second quarter of 2014 would not support commercial operations.

Acquisition of interests in Crump Geyser and North Valley Geothermal projects

On August 5, 2014, the Company signed a definitive Purchase and Sale Agreement with Alternative Earth Resources Inc. (“AER”), pursuant to which the Company paid $1.5 million in cash and (i) purchased AER's (a) 50% interest in Crump Geyser Company (“CGC”), which holds the rights to the Crump Geyser geothermal project, and (b) rights to the North Valley geothermal project (ii) obtained an option, exercisable over a four-year period, to purchase certain of AER's New Truckhaven geothermal lease. Prior to this transaction, CGC was consolidated by the Company as variable interest entity. As a result of the acquisition of the remaining interest, the Company continues to consolidate Crump, but now as a wholly owned indirect subsidiary, and so the carrying value of the non-controlling interest of CGC of $1.0 million was reclassified to the Company's equity and the difference of $0.2 million between the fair value of the consideration paid and the related carrying value of the nonconrolling interest acquired was recorded within “additional paid-in capital” in the condensed consolidated statement of equity.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(Unaudited)

Concentration of credit risk

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of temporary cash investments and accounts receivable.

The Company places its temporary cash investments with high credit quality financial institutions located in the United States ("U.S.") and in foreign countries. At September 30, 2014 and December 31, 2013, the Company had deposits totaling $23,016,000 and $13,805,000, respectively, in seven U.S. financial institutions that were federally insured up to $250,000 per account. At September 30, 2014 and December 31, 2013, the Company's deposits in foreign countries amounted to approximately $31,279,000 and $56,133,000, respectively.

At September 30, 2014 and December 31, 2013, accounts receivable related to operations in foreign countries amounted to approximately $42,914,000 and $32,231,000, respectively. At September 30, 2014 and December 31, 2013, accounts receivable from the Company's primary customers (as described immediately below) amounted to approximately 54.1% and 35.0% of the Company's accounts receivable, respectively.

Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy, Inc.) accounted for 14.6% and 15.3% of the Company's total revenues for the three months ended September 30, 2014 and 2013, respectively, and 16.6% and 17.0% for the nine months ended September 30, 2014 and 2013, respectively.

Southern California Edison accounted for 19.8% and 20.9% of the Company's total revenues for the three months ended September 30, 2014 and 2013, respectively, and 15.2% and 14.9% for the nine months ended September 30, 2014 and 2013, respectively.

Hawaii Electric Light Company accounted for 7.3% and 8.7% of the Company's total revenues for the three months ended September 30, 2014 and 2013, respectively, and 8.8% and 8.9% for the nine months ended September 30, 2014 and 2013, respectively.

Kenya Power and Lighting Co. Ltd. accounted for 15.7% and 13.9% of the Company's total revenues for the three months ended September 30, 2014 and 2013, respectively, and 15.6% and 10.9% for the nine months ended September 30, 2014 and 2013, respectively.

The Company performs ongoing credit evaluations of its customers' financial condition. The Company has historically been able to collect on all of its receivable balances, and accordingly, no provision for doubtful accounts has been made.

NOTE 2 — NEW ACCOUNTING PRONOUNCEMENTS

New accounting pronouncements effective in the nine-month period ended September 30, 2014

Presentation of Unrecognized Tax Benefits

In July 2013, the Financial Accounting Standards Board ("FASB") clarified the accounting guidance on presentation of the unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The guidance states that an unrecognized tax benefit (or a portion thereof) should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except for certain exceptions specified in the guidance. The exceptions include when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to reduce any income taxes that would result from the disallowance of a tax position or the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, the unrecognized tax benefit should be presented in the financial statements as a liability and not be combined with deferred tax assets. The assessment of whether a deferred tax asset is available is based on the unrecognized tax benefit and deferred tax asset that exist at the reporting date and is to be made assuming the disallowance of the tax position at the reporting date. This accounting update is effective for fiscal periods after December 15, 2013. The provision was applied prospectively to all unrecognized tax benefits that exist on January 1, 2014. The adoption of this guidance did have a material impact on the condensed consolidated financial statements.

New accounting pronouncements effective in future periods

Reporting Discontinued Operations and Disclosures

In April 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.* The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components of the Company.

Revenues from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenues from Contracts with Customers,* Topic 606, which was a joint project of the FASB and the International Accounting Standards Board to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The update provides that an entity should recognize revenue in connection with the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Specifically, an entity is required to apply each of the following steps: (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contracts; (3) determine the transaction price; (4) allocate the transaction price to the performance obligation in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. The amendments in this update are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The Company is currently evaluating the potential impact, if any, of the adoption of these amendments on its consolidated financial statements.

NOTE 3 — INVENTORIES

Inventories consist of the following:

	September 30,	**December 31,**

	2014	2013
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$10,412	$ 6,326
Self-manufactured assembly parts and finished products	6,925	15,963
Total	$17,337	$ 22,289

NOTE 4 — UNCONSOLIDATED INVESTMENTS

Unconsolidated investments consist of the following:

	September 30, 2014	December 31, 2013
	(Dollars in thousands)	
Sarulla	$1,339	$ 7,076

The Sarulla Project

The Company (through a subsidiary) is a 12.75% equity stake member of a consortium (the "Sarulla Consortium") which is in the process of developing the Sarulla geothermal power project in Indonesia with expected generating capacity of approximately 330 megawatts ("MW"). The Sarulla project is located in Tapanuli Utara, North Sumatra, Indonesia and will be owned and operated by the consortium members under the framework of a Joint Operating Contract ("JOC") and Energy Sales Contract ("ESC") that were signed on April 4, 2013. Under the JOC, PT Pertamina Geothermal Energy, the concession holder for the project, has provided the consortium with the right to use the geothermal field, and under the ESC, PT PLN, the state electric utility, will be the off-taker at Sarulla for a period of 30 years. In addition to its equity holdings in the consortium, the Company designed the Sarulla plant and is expected to supply its Ormat Energy Converters ("OECs") to the power plant. The supply contract was signed on October 2013.

The consortium has started preliminary testing and development activities at the site and signed an engineering procurement and construction agreement ("EPC") with an unrelated third party. The project will be constructed in three phases of 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant's efficiency.

On May 16, 2014, the consortium reached financial closing of $1.17 billion financing agreements to finance the development of the Sarulla project with a consortium of lenders comprised of Japan Bank for International Cooperation ("JBIC"), the Asian Development Bank and six commercial banks and obtained construction and term loan under limited recourse financing package backed by political risk guarantee from JBIC.

Of the $1.17 billion, $0.1 billion (which was drawn down by the Sarulla project company on May 23, 2014) bears a fixed interest rate and $1.07 billion bears interest at a rate linked to Libor.

The Sarulla consortium entered into interest rate swap agreements with various international banks in order to fix the Libor interest rate on up to $0.96 billion of the $1.07 billion credit facility at a rate of 3.4565%. The interest rate swap became effective as of June 4, 2014 along with the second draw-down by the project company of $50.0 million.

The Sarulla project company has accounted for the interest rate swap as a cash flow hedge upon which changes in the fair value of the hedging instrument, relative to the effective portion, will be recorded in other comprehensive income. As such, during the period, the project recorded a loss equal to $40.5 million, of which the Company's share was $5.2 million which was recorded in other comprehensive income

The first phase of operations is expected to commence in 2016 and the remaining two phases of operations are scheduled to commence within 18 months thereafter. The Company will supply its Ormat Energy Converters to the power plant and has added the $254.0 million supply contract to its product segment backlog. According to the current plan, the Company started to recognize revenue from the project during the third quarter of 2014 and will continue to recognize revenues over the course of the next three to four years. For the three and nine months ended September 30, 2014, the Company recognized Products revenues of $13.8 million.

During the first nine months of 2014, the Company made additional investment contributions of $0.6 million to the Sarulla project, consistent with its pro rata share in the consortium.

The Company's share in the results of operations of the Sarulla project was not significant for each of the periods presented in these condensed consolidated financial statements.

NOTE 5 — FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value measurement guidance clarifies that fair value is an exit price, representing the amount that would be received upon selling an asset or paid upon transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or liability. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy under the fair value measurement guidance are described below:

Level 1 — Unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities;

Level 2 — Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability;

Level 3 — Prices or valuation techniques that require inputs that are both significant to the fair value measurement and unobservable (supported by little or no market activity).

The following table sets forth certain fair value information at September 30, 2014 and December 31, 2013 for financial assets and liabilities measured at fair value by level within the fair value hierarchy, as well as cost or amortized cost. As required by the fair value measurement guidance, assets and liabilities are classified in their entirety based on the lowest level of inputs that is significant to the fair value measurement.

	Carrying value at September 30,	Fair Value at September 30, 2014			
	2014	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$116,118	$116,118	$116,118	$—	$ —
Derivatives:					
Swap transaction on oil price[1]	1,134	1,134	—	1,134	—
Swap transaction on natural gas price[2]	502	502	—	502	—
Liabilities:					
Current liabilities:					
Currency forward contracts[3]	(2,183)	(2,183)	—	(2,183)	—
	$115,571	$115,571	$116,118	$(547)	$ —

	Carrying value at December 31,	Fair Value at December 31, 2013			
	2013	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$40,015	$40,015	$40,015	$—	$ —
Derivatives:					
Currency forward contracts[3]	2,290	2,290	—	2,290	—
Liabilities					
Current liabilities:					
Derivatives:					
Swap transaction on oil price[1]	(2,490)	(2,490)	—	(2,490)	—
Swap transaction on natural gas price[2]	(341)	(341)	—	(341)	—
	$39,474	$39,474	$40,015	$(541)	$ —

(1) This amount relates to derivatives which represent swap contracts on oil prices, valued primarily based on observable inputs, including forward and spot prices for related commodity indices, and are included within "prepaid expenses and other" and "accounts payable and accrued expenses" in the condensed consolidated balance sheet with the corresponding gain or loss being recognized within "electricity revenues" in the condensed consolidated statement of operations and comprehensive income (loss).

(2) This amount relates to derivatives which represent swap contracts

on natural gas prices, valued primarily based on observable inputs, including forward and spot prices for related commodity indices, and are included within "prepaid expenses and other" and "accounts payable and accrued expenses" in the condensed consolidated balance sheet with the corresponding gain or loss being recognized within "electricity revenues" in the condensed consolidated statement of operations and comprehensive income (loss).

(3) This amount relates to derivatives which represent currency forward contracts, valued primarily based on observable inputs, including forward and spot prices for

currencies, netted against contracted rates and then multiplied against notational amounts, and are included within "prepaid expenses and other" in the condensed consolidated balance sheet with the corresponding gain or loss being recognized within "foreign currency translation and transaction gains (losses)" in the condensed consolidated statement of operations and comprehensive income (loss).

The amounts set forth in the tables above include investments in debt instruments and money market funds (which are included in cash equivalents). Those securities and deposits are classified within Level 1 of the fair value hierarchy because they are valued using quoted market prices in an active market.

The following table presents the amounts of gain (loss) recognized in the condensed consolidated statements of operations and comprehensive income (loss) on derivative instruments not designated as hedges:

Derivatives not designated as hedging instruments	**Location of recognized gain (loss)**	**Amount of recognized gain (loss)**			
		Three Months Ended September 30,		**Nine Months Ended September 30,**	
		2014	**2013**	**2014**	**2013**
		(Dollars in thousands)		**(Dollars in thousands)**	
Put options on oil price	Electricity revenues	$—	$(824)	$—	$(1,256)
Swap transaction on oil price	Electricity revenues	1,657	—	1,885	(294)
Swap transaction on natural gas price	Electricity revenues	2,295	477	(609)	81
Currency forward contracts	Foreign currency translation and transaction gains (losses)	(2,422)	1,970	(2,430)	4,895
		$1,530	$1,623	$(1,154)	$3,426

On September 3, 2013, the Company entered into an NGI swap contract with a bank for notional quantity of approximately 4.4 million MMbtu for settlement effective January 1, 2014 until December 31, 2014, in order to reduce its exposure to NGI below $4.035 per MMbtu under its PPAs with Southern California Edison. The contract did not have up-front costs. Under the terms of this contract, the Company makes floating rate payments to the bank and receives fixed rate payments from the bank on each settlement date. The swap contract has monthly settlement whereby the difference between the fixed price of $4.035 per MMbtu and the market price on the first commodity business day on which the relevant commodity reference price is published in the relevant calculation period (January 1, 2014 to December 1, 2014) is being settled on a cash basis.

On October 16, 2013, the Company entered into an NGI swap contract with a bank for notional quantity of approximately 4.2 million MMbtu for settlement effective January 1, 2014 until December 31, 2014, in order to reduce its exposure to NGI below $4.103 per MMbtu under its PPAs with Southern California Edison. The contract did not have any up-front costs. Under the terms of this contract, the Company makes floating rate payments to the bank and receives fixed rate payments from the bank on each settlement date. The swap contract has monthly settlements whereby the difference between the fixed price of $4.103 per MMbtu and the market price on the first commodity business day on which the relevant commodity reference price is published in the relevant calculation period (January 1, 2014 to December 1, 2014) is being settled on a cash basis.

On October 16, 2013, the Company entered into a New York Harbor ULSD swap contract with a bank for notional quantity of 275,000 BBL effective from January 1, 2014 until December 31, 2014 to reduce the Company's exposure to fluctuations in the energy rate caused by fluctuations in oil prices under the 25 MW PPA for the Puna complex. The Company entered into this contract because the swap had a high correlation with the avoided costs (which are incremental costs that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others) that HELCO uses to calculate the energy rate. The contract did not have any up-front costs. Under the term of this contract, the Company will make floating rate payments to the bank and receive fixed rate payments from the bank on each settlement date ($125.15 per BBL). The swap contract has monthly settlements whereby the difference between the fixed price and the monthly average market price will be settled on a cash basis.

On March 6, 2014, the Company entered into an NGI swap contract with a bank for notional quantity of approximately 2.2 million MMbtu for settlement effective January 1, 2015 until March 31, 2015, in order to reduce its exposure to NGI below $4.95 per MMbtu under its PPAs with Southern California Edison. The contract did not have any up-front costs. Under the terms of this contract, the Company will make floating rate payments to the bank and receive fixed rate payments from the bank on each settlement date. The swap contract has monthly settlements whereby the difference between the fixed price of $4.95 per MMbtu and the market price on the first commodity business day on which the relevant commodity reference price is published in the relevant calculation period (January 1, 2015 to March 1, 2015) will be settled on a cash basis.

The foregoing swap transactions have not been designated as hedge transactions and are marked to market with the corresponding gains or losses recognized within "Electricity revenues" in the condensed consolidated statements of operations and comprehensive income. For the nine months ended September 30, 2014 and 2013, the Company recognized a net gain and a net loss from these transactions of $1.3 million and $1.5 million, respectively. For the three months ended September 30, 2014 and 2013, the Company recognized a net gain and a net loss from these transactions of $4.0 million and $0.3 million, respectively.

There were no transfers of assets or liabilities between Level 1 and Level 2 during the nine months ended September 30, 2014.

The fair value of the Company's long-term debt approximates its carrying amount, except for the following:

	Fair Value		**Carrying Amount**	
	September 30, 2014	**December 31, 2013**	**September 30, 2014**	**December 31, 2013**
	(Dollars in millions)		**(Dollars in millions)**	
Olkaria III loan - DEG	$36.6	$ 40.3	$35.5	$ 39.5
Olkaria III loan - OPIC	276.8	279.6	287.1	299.9
Amatitlan loan	—	34.8	—	31.5
Senior secured notes:				
Ormat Funding LLC ("OFC")	78.0	83.5	72.5	90.8
OrCal Geothermal LLC ("OrCal")	64.3	65.8	63.2	66.2
OFC 2 LLC ("OFC 2")	233.9	119.0	274.5	144.4
Senior unsecured bonds	264.9	270.6	250.4	250.6
Loans from institutional investors	14.2	20.1	13.9	19.5

The fair value as of December 31, 2013, of OFC senior secured notes was determined using observable market prices as these securities are traded. The fair value as of September 30, 2014 of the long-term debt is determined by a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of estimated current borrowing rates. The fair value of revolving lines of credit is determined using a comparison of market-based price sources that are reflective of similar credit ratings to those of the Company.

On June 20, 2014, Phase I of Tuscarora facility achieved project completion under the OFC 2 Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement, the Company recalibrated the original financing assumptions and as a result the loan amount was adjusted through a principal prepayment of approximately $4.3 million.

On August 29, 2014, OFC 2, a wholly-owned indirect subsidiary of the Company signed a $140.0 million loan under the OFC 2 senior secured notes to finance the construction of the McGinness Hills Phase 2 project in Nevada. This drawdown is the last tranche available under the OFC 2 Note Purchase Agreement with John Hancock Life Insurance Company and guaranteed by the U.S. Department of Energy's Loan Programs Office. The $140.0 million loan, which matures in December 2032, carries a 4.61% coupon with principal to be repaid on a quarterly basis. The OFC 2 Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated "BBB" by Standard & Poor's.

In connection with the anticipated drawdown, on August 13, 2014, the Company entered into an on-the-run interest rate lock agreement with a financial institution with a termination date of August 15, 2014. This on-the-run interest rate lock agreement had a notional amount of $140.0 million and was designated by the Company to be a cash flow hedge. The objective of this cash flow hedge was to eliminate the variability in the changes in the 10-year U.S. Treasury rate as that is one of the components in the annual interest rate of the OFC 2 loan that was forecasted to be fixed on August 15, 2014. As such, the Company hedged the variability in total proceeds attributable to changes in the 10-year U.S. Treasury rate for the forecasted issuance of fixed rate OFC 2 loan. On August 18, 2014, which was the settlement date, the Company paid $1.5 million to the counterparty of the on-the-run interest rate lock agreement.

The Company concluded that the cash flow hedge was fully effective with no ineffective portion and no amounts excluded from the effectiveness testing, thus the total loss from the cash flow hedge was fully recognized in “Loss in respect of derivatives instruments designated for cash flow hedge” under other comprehensive income of $0.9 million noted above, which was net of related taxes of $0.6 million. The cash flow hedge loss recorded will be amortized over the life of the OFC 2 loan using the effective interest method. The Company expects to reclassify $0.2 of the loss from “Accumulated other comprehensive income (loss)” into interest expense during the next twelve months.

On September 30, 2014, Ortitlan, a wholly-owned indirect subsidiary of the Company, prepaid the outstanding amount of approximately $30.0 million loan with EIG Global Project Fund II, Ltd. (formerly TCW). The $42.0 million loan was signed in 2009 to refinance the Company's investment in the 20 MW Amatitlan geothermal power plant located in Guatemala. This repayment resulted in a one-time charge to interest expense of approximately $1.1 million, consisting of (i) prepayment premium of $0.6 million, and (ii) write-off of related deferred financing costs amounting to a $0.5 million.

The carrying value of other financial instruments, such as revolving lines of credit, deposits, and other long-term debt approximates fair value.

The following table presents the fair value of financial instruments as of September 30, 2014:

	Level 1	**Level 2**	**Level 3**	**Total**
	(Dollars in millions)			
Olkaria III loan - DEG	$—	$—	$36.6	$36.6
Olkaria III loan - OPIC	—	—	276.8	276.8
Senior secured notes:				
OFC	—	—	78.0	78.0
OrCal	—	—	64.3	64.3
OFC 2	—	—	233.9	233.9
Senior unsecured bonds	—	—	264.9	264.9
Loan from institutional investors	—	—	14.2	14.2
Other long-term debt	—	15.0	—	15.0
Revolving lines of credit	—	28.1	—	28.1
Deposits	21.7	—	—	21.7

The following table presents the fair value of financial instruments as of December 31, 2013:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III loan - DEG	$—	$—	$40.3	$40.3
Olkaria III loan - OPIC	—	—	279.6	279.6
Amatitlan loan	—	—	34.8	34.8
Senior secured notes:				
OFC	—	83.5	—	83.5
OrCal	—	—	65.8	65.8
OFC 2	—	—	119.0	119.0
Senior unsecured bonds	—	—	270.6	270.6
Loan from institutional investors	—	—	20.1	20.1
Other long-term debt	—	23.3	—	23.3
Revolving lines of credit	—	112.0	—	112.0
Deposits	21.3	—	—	21.3

NOTE 6 — STOCK-BASED COMPENSATION

The 2004 Incentive Compensation Plan

In 2004, the Company’s Board of Directors adopted the 2004 Incentive Compensation Plan (“2004 Incentive Plan”), which provides for the grant of the following types of awards: incentive stock options, non-qualified stock options, restricted stock, stock appreciation rights (“SARs”), stock units, performance awards, phantom stock, incentive bonuses, and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2004 Incentive Plan, a total of 3,750,000 shares of the Company’s common stock have been reserved for issuance, all of which could be issued as options or as other forms of awards. Options and SARs granted to employees under the 2004 Incentive Plan cliff vest and are exercisable from the grant date as follows: 25% after 24 months, 25% after 36 months, and the remaining 50% after 48 months. Options granted to non-employee directors under the 2004 Incentive Plan cliff vest and become fully exercisable one year after the grant date. Vested stock-based awards may be exercised for up to ten years from the date of grant. The shares of common stock will be issued upon exercise of options or SARs from the Company’s authorized share capital. The 2004 Incentive Plan expired in May 2012 upon adoption of the 2012 Incentive Plan, except as to share based awards outstanding on that date.

The 2012 Incentive Compensation Plan

In May 2012, the Company's shareholders adopted the 2012 Incentive Compensation Plan (as amended the "2012 Incentive Plan"), which provides for the grant of the following types of awards: incentive stock options, non-qualified stock options, restricted stock, SARs, stock units, performance awards, phantom stock, incentive bonuses, and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2012 Incentive Plan, a total of 4,000,000 shares of the Company's common stock have been reserved for issuance, all of which could be issued as options or as other forms of awards. Options and SARs granted to employees under the 2012 Incentive Plan will vest and become exercisable as follows: 25% vest 24 months after the grant date, an additional 25% vest 36 months after the grant date, and the remaining 50% vest 48 months after the grant date. Options granted to non-employee directors under the 2012 Incentive Plan will vest and become exercisable one year after the grant date. The term of stock-based awards typically ranges from six to ten years from the date of grant. The shares of common stock will be issued upon exercise of options or SARs from the Company's authorized share capital.

The 2012 Incentive Plan was amended during the first half of 2014. The key amendments are as follows:

Increase of per grant limit: Section 15(a) of the 2012 Incentive Plan was amended to allow the grant of up to 400,000 shares of the Company's common stock with respect to the initial grant of an equity award to newly hired executive officers in any calendar year; and

Acceleration of vesting: Section 15(l) of the 2012 Incentive Plan was amended to clarify the Company's ability to provide in the applicable award agreement that part and/or all of the award will be accelerated upon the occurrence of certain predetermined events and/or conditions, such as a "change in control" (as defined in the 2012 Incentive Plan).

On February 11, 2014, the Company granted its Chief Financial Officer options to purchase 32,500 shares of common stock under the 2012 Incentive Plan. The exercise price of each option is $24.57, which represented the fair market value of the Company's common stock on the grant date. Such options will expire five years from the date of grant and will vest in equal annual installments over a period of three years from the grant date, subject to acceleration upon a change of control.

The fair value of each stock option on the grant date was $5.78. The Company calculated the fair value of each stock option on the date of grant using the Black-Scholes valuation model based on the following assumptions:

Risk-free interest rates	0.81	%
Expected life (in years)	3.375	
Dividend yield	0.80	%
Expected volatility	33.50	%
Forfeiture rate	0.00	%

On April 2, 2014, the Company granted its newly appointed Chief Executive Officer options to purchase up to an aggregate of 400,000 shares of common stock under the 2012 Incentive Plan. The exercise price of each option is $29.52 per share, which represented the fair market value of the Company's common stock on the date of the grant. Options to purchase 300,000 shares of common stock will expire six years following the date of grant and will vest in equal annual installments over four years from the grant date, subject to acceleration in the event of a change of control. The remaining options to purchase 100,000 shares of common stock will vest on March 31, 2021, subject to acceleration associated with a change of control, and will expire seven and a half years from the date of grant.

The fair value of each option on the grant date was $8.33 for grant of options to purchase 300,000 shares of common stock, and $12.88 for the grant of options to purchase 100,000 shares of common stock. The Company calculated the fair value of each stock option on the date of grant using the Black-Scholes valuation model based on the following assumptions:

	Grant of options to purchase 300,000 shares of common stock		**Grant of options to purchase 100,000 shares of common stock**	
Risk-free interest rates	2.36	%	1.64	%
Expected life (in years)	7.25		4.75	
Dividend yield	0.90	%	0.90	%
Expected volatility	42.80	%	33.10	%

NOTE 7 — INTEREST EXPENSE, NET

The components of interest expense, net, are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
	(Dollars in thousands)		**(Dollars in thousands)**	
Interest related to sale of tax benefits	$3,430	$3,479	$9,678	$9,233
Other interest expense	19,910	16,811	57,139	48,820
Less — amount capitalized	(846)	(1,831)	(1,733)	(6,227)
	$22,494	$18,459	$65,084	$51,826

NOTE 8 — EARNINGS PER SHARE

Basic earnings per share attributable to the Company's stockholders ("earnings per share") is computed by dividing net income or loss attributable to the Company's stockholders by the weighted average number of shares of common stock outstanding for the period. The Company does not have any equity instruments that are dilutive, except for employee stock-based awards.

The table below shows the reconciliation of the number of shares used in the computation of basic and diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	**2013**	**2014**	**2013**
	(In thousands)		**(In thousands)**	
Weighted average number of shares used in computation of basic earnings per share	45,690	45,438	45,594	45,433
Add:				
Additional shares from the assumed exercise of employee stock-based awards	412	56	323	21
Weighted average number of shares used in computation of diluted earnings per share	46,102	45,494	45,917	45,454

The number of stock-based awards that could potentially dilute future earnings per share and that were not included in the computation of diluted earnings per share because to do so would have been anti-dilutive was 3,344,331 and 4,999,298 for the three months ended September 30, 2014 and 2013, respectively, and 3,257,456 and 5,312,238 for the nine months ended September 30, 2014 and 2013, respectively.

NOTE 9 — BUSINESS SEGMENTS

The Company has two reporting segments: Electricity and Product Segments. These segments are managed and reported separately as each offers different products and serves different markets. The Electricity Segment is engaged in the sale of electricity from the Company's power plants pursuant to PPAs. The Product Segment is engaged in the manufacture, including design and development, of turbines and power units for the supply of electrical energy and in the associated construction of power plants utilizing the power units manufactured by the Company to supply energy from geothermal fields and other alternative energy sources. Transfer prices between the operating segments are determined based on current market values or cost plus markup of the seller's business segment.

Summarized financial information concerning the Company's reportable segments is shown in the following tables:

	Electricity	Product	Consolidated
	(Dollars in thousands)		
Three Months Ended September 30, 2014:			
Net revenues from external customers	$102,506	$37,736	$ 140,242
Intersegment revenues	—	7,244	7,244
Operating income	32,411	11,377	43,788
Segment assets at period end *	2,083,715	88,198	2,171,913
* Including unconsolidated investments	1,339	—	1,339
Three Months Ended September 30, 2013:			
Net revenues from external customers	$88,994	$41,755	$ 130,749
Intersegment revenues	—	4,329	4,329
Operating income	20,732	9,065	29,797
Segment assets at period end *	2,048,021	120,314	2,168,335
* Including unconsolidated investments	5,419	—	5,419
Nine Months Ended September 30, 2014:			
Net revenues from external customers	$289,015	$121,266	$ 410,281
Intersegment revenues	—	43,580	43,580
Operating income	72,850	35,839	108,689
Segment assets at period end *	2,083,715	88,198	2,171,913
* Including unconsolidated investments	1,339	—	1,339
Nine Months Ended September 30, 2013:			
Net revenues from external customers	$245,005	$157,329	$ 402,334
Intersegment revenues	—	29,731	29,731
Operating income	42,057	33,286	75,343
Segment assets at period end *	2,048,021	120,314	2,168,335
* Including unconsolidated investments	5,419	—	5,419

18

Reconciling information between reportable segments and the Company’s consolidated totals is shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(Dollars in thousands)		(Dollars in thousands)	
Operating income	$43,788	$29,797	$108,689	$75,343
Interest income	35	742	236	870
Interest expense, net	(22,494)	(18,459)	(65,084)	(51,826)
Foreign currency translation and transaction gains (losses)	(2,946)	1,258	(3,639)	3,844
Income attributable to sale of tax benefits	5,487	5,027	18,334	14,342
Gain from sale of property, plant and equipment	—	—	7,628	—
Other non-operating income, net	243	137	649	1,583
Total income, before income taxes, discontinued operations and equity in income (losses) of investees	$24,113	$18,502	$66,813	$44,156

NOTE 10 — COMMITMENTS AND CONTINGENCIES

In December 2012, Laborers’ International Union of North America Local Union No. 783 (“LiUNA”), an organized labor union, filed a petition in Mono County Superior Court, naming Mono County, California and the Company as defendant and real party in interest, respectively. The petitioners brought this action to challenge the November 13, 2012 decision of the Mono County Board of Supervisors in adopting Resolutions No. 12-78, denying petitioners’ administrative appeal of the Planning Commission’s approval of Conditional Use Permit (“CUP”), adoption of findings under the California Environmental Quality Act (“CEQA”) and adoption of the final environmental impact report (“EIR”) for the Mammoth Pacific enhancement. The Company has successfully defended itself against the petition, which has been denied by the court.

On July 8, 2014, Global Community Monitor, LiUNA, and two residents of Bishop, California filed a complaint in the United States District Court for the Eastern District of California, alleging that Mammoth Pacific, L.P., Ormat Technologies, Inc. and Ormat Nevada, Inc. are operating three geothermal generating plants in Mammoth Lakes, California (MP-1; MP-II and PLES-I) in violation of the federal Clean Air Act (“CAA”) and Great Basin Unified Air Pollution Control District (“District”) rules. The Company is continuing to review the complaint and believes that it is without merit, and intends to vigorously defend itself against the allegations set forth in the complaint and to take all necessary legal action to have the complaint dismissed. Filing of the complaint in and of itself does not have any immediate adverse implications for the Mammoth plants.

In January 2014, the Company learned that two former employees alleged in a “qui tam” complaint filed in the United States District Court for the Southern District of California that the Company submitted fraudulent applications and certifications to obtain grants. The United States Department of Justice has declined to intervene. The former employees have proceeded on their own and served the Company with their initial complaint in April 2014, and then filed an amended complaint in May 2014. The Company is investigating, and is defending against the amended complaint. This includes that, pursuant to the Company’s motion to move the venue of the proceeding, the file was reassigned from the United States District Court for the Southern District of California to the District of Nevada. In addition, the Company has filed a motion to dismiss the amended complaint, in response to which the complainants have filed responses, and the United States has filed a statement of interest regarding the Company's claim that the False Claims Act’s “Tax Bar” excludes such Act’s application to the Company, and urged the court to reject the Company's argument, while continuing to take no position as to the overall sufficiency of the complainants' complaint. The motion to dismiss is pending before the Nevada United States District Court. The Company continues to believe that the allegations of the lawsuit have no merit, and it will continue to defend itself vigorously.

In addition, from time to time, the Company is named as a party in various other lawsuits, claims and other legal and regulatory proceedings that arise in the ordinary course of its business. These actions typically seek, among other things, compensation for alleged personal injury, breach of contract, property damage, punitive damages, civil penalties or other losses, or injunctive or declaratory relief. With respect to such lawsuits, claims and proceedings, the Company accrues reserves when a loss is probable and the amount of such loss can be reasonably estimated. It is the opinion of the Company’s management that the outcome of these proceedings, individually and collectively, will not be material to the Company’s consolidated financial statements as a whole.

NOTE 11 — INCOME TAXES

The Company's effective tax rate for the three months ended September 30, 2014 and 2013 was 26.7% and 28.1%, respectively. The Company's effective tax rate for the nine months ended September 30, 2014 and 2013 was 26.5% and 34.0%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the three and nine months ended September 30, 2014 primarily due to: (i) a full valuation allowance against the Company's U.S. deferred tax assets in respect of net operating loss ("NOL") carryforwards and unutilized tax credits (see below); (ii) lower tax rates in Israel and (iii) a tax credit and tax exemption related to the Company's subsidiaries in Guatemala. The effect of the tax credit and tax exemption for the three months ended September 30, 2014 and 2013, was $895,000 and $495,000, respectively, and for the nine months ended September 30, 2014 and 2013, was $2,921,000 and $1,890,000.

At December 31, 2013, the Company had U.S. federal NOL carryforwards of approximately $235.4 million and state NOL carryforwards of approximately $218.1 million available to reduce future taxable income, which expire between 2021 and 2032 for federal NOLs and between 2014 and 2032 for state NOLs. Investment tax credits in the amount of $0.7 million at December 31, 2013 are available for a 20-year period and expire between 2022 and 2024. Production tax credits in the amount of $71.3 million at December 31, 2013 are available for a 20-year period and expire between 2026 and 2032.

Realization of the deferred tax assets is dependent on generating sufficient taxable income in appropriate jurisdictions prior to expiration of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies were considered in determining the amount of valuation allowance. A full valuation allowance was recorded against the U.S. deferred tax assets as of December 31, 2013 and September 30, 2014, as at these points in time it was more likely than not that the deferred tax assets will not be realized. If sufficient evidence of the Company's ability to generate taxable income is established in the future, the Company may be required to reduce this valuation allowance, resulting in income tax benefits in its condensed consolidated statement of operations and comprehensive income (loss).

The Company believes that based on its plans to increase the operations outside of the U.S., the cash generated from the Company's operations outside of the U.S. will be reinvested outside of the U.S. In addition, the Company's U.S. sources of cash and liquidity are sufficient to meet its needs in the U.S. and, accordingly, the Company does not currently plan to repatriate the funds it has designated as being permanently invested outside the U.S. If the Company changes its plans, it may be required to accrue and pay U.S. taxes to repatriate these funds.

The Company's subsidiary, Ormat Systems Ltd. ("Ormat Systems"), received "Benefited Enterprise" status under Israel's Law for Encouragement of Capital Investments, 1959 (the "Investment Law"), with respect to two of its investment programs. As a Benefited Enterprise, Ormat Systems was exempt from Israeli income taxes with respect to income derived from the first benefited investment for a period of two years beginning in 2004, and thereafter such income was subject to reduced Israeli income tax rates, which will not exceed 25% for an additional five years until 2010.

Ormat Systems was also exempt from Israeli income taxes with respect to income derived from the second benefited investment for a period of two years beginning in 2007. Thereafter, such income is subject to reduced Israeli income tax rates, which did not exceed 25% for an additional five years until 2013. These benefits are subject to certain conditions, including among other things, that all transactions between Ormat Systems and its affiliates are done on an arm's length basis, and that the management of Ormat Systems will be located in, and the control will be conducted from, Israel during the entire period of the tax benefits. A change in control of Ormat Systems would need to be reported to the Israel Tax Authority in order for Ormat Systems to maintain the tax benefits. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax will apply to all qualified income of certain industrial companies, as opposed to the previous law's incentives that are limited to income from a "Benefited Enterprise" during their benefits period. According to the amendment, the uniform tax rate applicable to the zone where the production facilities of Ormat Systems are located would be 15% in 2011 and 2012, 12.5% in 2013 and 16% in 2014 and thereafter. Under the transitory provisions of the new legislation, Ormat Systems had the option either to irrevocably comply with the new law while waiving benefits provided under the previous law or to continue to comply with the previous law during a transition period with the option to move from the previous law to the new law at any stage. Ormat Systems decided to irrevocably comply with the new law starting in 2011.

A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

	Nine Months Ended September 30,	
	2014	**2013**
	(Dollars in thousands)	
Balance at beginning of period	$4,950	$7,280
Additions based on tax positions taken in prior years	93	901
Additions based on tax positions taken in current year	563	697
Balance at end of period	$5,606	$8,878

NOTE 12 —TAX MONETIZATION TRANSACTIONS

OPC Transaction

In June 2007, the Company's wholly owned subsidiary Ormat Nevada Inc. ("Ormat Nevada") entered into agreements with affiliates of Morgan Stanley & Co. Incorporated and Lehman Brothers Inc. (Morgan Stanley Geothermal LLC and Lehman-OPC LLC), under which those investors purchased, for cash, interests in a newly formed subsidiary of Ormat Nevada, OPC LLC ("OPC"), entitling the investors to certain tax benefits (such as PTCs and accelerated depreciation) and distributable cash associated with four geothermal power plants.

The first closing under the agreements occurred in 2007 and covered the Company's Desert Peak 2, Steamboat Hills, and Galena 2 power plants. The investors paid $71.8 million at the first closing. The second closing under the agreements occurred in 2008 and covered the Galena 3 power plant. The investors paid $63.0 million at the second closing.

Ormat Nevada continues to operate and maintain the power plants. Under the agreements, Ormat Nevada initially received all of the distributable cash flow generated by the power plants, while the investors received substantially all of the production tax credits and taxable income or loss (together, the "Economic Benefits"). Once Ormat Nevada recovered the capital that it has invested in the power plants, which occurred in the fourth quarter of 2010, the investors began receiving both the distributable cash flow and the Economic Benefits. The investors' return is limited by the term of the transaction. Once the investors reach a target after-tax yield on their investment in OPC (the "OPC Flip Date"), Ormat Nevada will receive 95% of both distributable cash and taxable income, on a going forward basis. Following the OPC Flip Date, Ormat Nevada also has the option to buy out the investors' remaining interest in OPC at the then current fair market value or, if greater, the investors' capital account balances in OPC. Should Ormat Nevada exercise this purchase option, it would thereupon revert to being sole owner of the power plants.

The Class B membership units are provided with a 5% residual economic interest in OPC. The 5% residual interest commences on achievement by the investors of a contractually stipulated return that triggers the OPC Flip Date, as described above. The actual OPC Flip Date is not known with certainty and is determined by the operating results of OPC. This residual 5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments. Cash is distributed each period in accordance with the cash allocation percentages stipulated in the agreements. Until the fourth quarter of 2010, Ormat Nevada was allocated the cash earnings in OPC and therefore, the amount allocated to the 5% residual interest represented the noncash loss of OPC which principally represented depreciation on the property, plant and equipment. Beginning from the fourth quarter of 2010, the distributable cash is allocated to the Class B membership units. As a result of the acquisition by Ormat Nevada, on October 30, 2009, of all of the Class B membership units of OPC held by Lehman-OPC LLC (see below), the residual interest decreased to 3.5%. Such residual interest increased again to 5% on February 3, 2011 when Ormat Nevada sold its Class B membership units to JPM Capital Corporation ("JPM") (see below).

The Company's voting rights in OPC are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, the Company owns all of the Class A membership units, which represent 75% of the voting rights in OPC. The investors own all of the Class B membership units, which represent 25% of the voting rights in OPC. In the period from October 30, 2009 to February 3, 2011, the Company owned, through Ormat Nevada, all of the Class A membership units, which represented 75% of the voting rights in OPC, and 30% of the Class B membership units, which represented 7.5% of the voting rights of OPC. In total the Company owned 82.5% of the voting rights in OPC as of December 31, 2010. In that period, the investors owned 70% of the Class B membership units, which represented 17.5% of the voting rights of OPC. Other than in respect of customary protective rights, all operational decisions in OPC are decided by the vote of a majority of the membership units. Following the OPC Flip Date, Ormat Nevada's voting rights will increase to 95% and the investor's voting rights will decrease to 5%. Ormat Nevada retains the controlling voting interest in OPC both before and after the OPC Flip Date and therefore consolidates OPC.

On October 30, 2009, Ormat Nevada acquired from Lehman-OPC LLC all of the Class B membership units of OPC held by Lehman-OPC pursuant to a right of first offer for a price of $18.5 million. A substantial portion of the initial sale of the Class B membership units by Ormat Nevada was accounted for as a financing transaction. As a result, the repurchase of these interests at a discount resulted in a pre-tax gain of $13.3 million in the year ended December 31, 2009. In addition, an amount of approximately $1.1 million has been reclassified from noncontrolling interest to additional paid in capital representing the 1.5% residual interest of Lehman-OPC's Class B membership units.

On February 3, 2011, Ormat Nevada sold to JPM all of the Class B membership units of OPC that it had acquired on October 30, 2010 for a total sale price of $24.9 million in cash. The Company did not record any gain from the sale of its Class B membership interests in OPC to JPM. A substantial portion of the Class B membership units are accounted for as a financing transaction. As a result, the majority of these proceeds were recorded as a liability. In addition, $2.3 million has been reclassified from additional paid in capital to noncontrolling interest representing the 1.5% residual interest of JPM's Class B membership units.

ORTP Transaction

In January 2013, Ormat Nevada entered into agreements with JPM under which JPM purchased interests in a newly formed subsidiary of Ormat Nevada, ORTP, LLC ("ORTP"), entitling JPM to certain tax benefits (such as PTCs and accelerated depreciation) associated with certain geothermal power plants in California and Nevada.

Under the terms of the transaction, Ormat Nevada transferred the Heber complex, the Mammoth complex, the Ormesa complex, and the Steamboat 2 and 3, Burdette (Galena 1) and Brady power plants to ORTP, and sold class B membership units in ORTP to JPM. In connection with the closing, JPM paid approximately $35.7 million to Ormat Nevada and will make additional payments to Ormat Nevada of 25% of the value of PTCs generated by the portfolio over time. The additional payments are expected to be made until December 31, 2016 up to a maximum amount of $11.0 million of which we received $2.2 million in the first quarter of 2014.

Ormat Nevada will continue to operate and maintain the power plants. Under the agreements, Ormat Nevada will initially receive all of the distributable cash flow generated by the power plants, while JPM will receive substantially all of PTCs and the taxable income or loss (together, the "Economic Benefits"). JPM's return is limited by the terms of the transaction. Once JPM reaches a target after-tax yield on its investment in ORTP (the "ORTP Flip Date"), Ormat Nevada will receive 97.5% of the distributable cash and 95% of the taxable income, on a going forward basis. At any time during the twelve month period after the end of the fiscal year in which the ORTP Flip Date occurs (but no earlier than the expiration of five years following the date that the last of the power plants was placed in service for purposes of federal income taxes), Ormat Nevada also has the option to buy out JPM's remaining interest in ORTP at the then current fair market value. If Ormat Nevada were to exercise this purchase option, it would become the sole owner of the power plants again.

The Class B membership units entitle the holder to 5.0% (allocation of income and loss) and 2.5% (allocation of cash) residual economic interest in ORTP. The 5.0% and 2.5% residual interest commences on achievement by JPM of a contractually stipulated return that triggers the ORTP Flip Date. The actual ORTP Flip Date is not known with certainty. This residual 5.0% and 2.5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments.

The Company's voting rights in ORTP are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada the Company owns all of the Class A membership units, which represent 75% of the voting rights in ORTP. JPM owns all of the Class B membership units, which represent 25% of the voting rights of ORTP. Other than in respect of customary protective rights, all operational decisions in ORTP are decided by the vote of a majority of the membership units. Ormat Nevada retains the controlling voting interest in ORTP both before and after the ORTP Flip Date and therefore will continue to consolidate ORTP.

NOTE 13 — DISCONTINUED OPERATIONS

On May 30, 2013, the Company's wholly owned subsidiary, Ormat Holding Corp., sold the Momotombo Power Company ("MPC"), which operates the Momotombo power plant located in Nicaragua, to a third party for $7,751,000 approximately one year before the scheduled termination of the concession arrangement with the Nicaraguan owner. The Company recorded an after-tax gain on sale of approximately $3.6 million in the nine months ended September 30, 2013.

In conjunction with the sale, the Company's wholly owned subsidiary and the buyer signed a technical support agreement, whereby the subsidiary will provide technical consulting services, which can be terminated by either party with 60 days advance notice. The Company is of the opinion that the expected continuing cash flows from this agreement are insignificant and that there is no significant continuing involvement by the Company, including its subsidiaries, in the operations of the MPC after the sale. Therefore, the related income from operations prior to the date of the sale and the gain on the sale of the MPC have been included as discontinued operations in the condensed consolidated statements of operations and comprehensive income for all comparative periods presented.

The summarized financial information related to the discontinued operations is as follows:

	Nine Months Ended September 30, 2013 (Dollars in thousands)
Revenues - electricity	$ 4,866
Cost of revenues - electricity	(2,869)
Gross margin	1,997
Operating expenses:	
Selling and marketing expenses:	(192)
General and administrative expenses:	(140)
Operating income:	1,665
Income from discontinued operations before income taxes	5,311
Income tax provision	(614)
Total income from discontinued operations	$ 4,697

The net assets of the MPC as of May 30, 2013 were as follows:

	(Dollars in thousands)
Cash and cash equivalents	$ 52
Accounts receivable	2,274
Prepaid expenses and other	167
Property, plant and equipment	3,935
Accounts payable and accrued expenses	(493)
Deferred income taxes	(442)
Accrued severance pay	(313)
Other liabilities	(590)
Net assets	$ 4,590

NOTE 14 — SUBSEQUENT EVENTS

Cash dividend

On November 5, 2014, the Company's Board of Directors declared, approved and authorized payment of a quarterly dividend of $2.3 million ($0.05 per share) to all holders of the Company's issued and outstanding shares of common stock on November 20, 2014, payable on December 4, 2014.

Potential restructuring with parent company

On October 29, 2014, following a report to that effect issued to the Tel Aviv Stock Exchange and the Israeli Security Authority by its parent entity, Ormat Industries, Ltd. ("OIL"), the Company announced that the two companies are considering a possible group corporate reorganization. Pursuant to the proposed transaction, the Company would acquire OIL by issuing shares of common stock in the Company to OIL's shareholders in exchange for all of the OIL shareholders' shares in OIL, based upon an exchange ratio to be agreed upon between the parties. If approved and consummated, the transaction would eliminate OIL's majority ownership interest in, and control of, Ormat Technologies, and OIL would become an indirect wholly owned subsidiary of Ormat Technologies.

The Company has established a special committee of independent directors with full authority to consider the proposed transaction, including to negotiate the exchange ratio and make a recommendation to the Board of Directors, or to reject the proposed transaction. The special committee has retained independent legal and financial advisors to assist the committee in considering the proposed transaction.

There can be no assurance at this stage whether the proposed transaction will be approved and consummated and, if consummated, what the terms (including the exchange ratio) thereof would be. Any potential transaction is subject to the negotiation and execution of definitive agreements, as well as to customary conditions and approvals, including (without limitation) regulatory approvals, an affirmative recommendation of the special committee of the Board of Directors, an approval of the full Board of Directors, and the approval of the shareholders of each of the Company and OIL.

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

Cautionary Note Regarding Forward-Looking Statements

This quarterly report on Form 10-Q includes "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this quarterly report that address activities, events or developments that we expect or anticipate will or may occur in the future, including such matters as our projections of annual revenues, expenses and debt service coverage with respect to our debt securities, future capital expenditures, business strategy, competitive strengths, goals, development or operation of generation assets, market and industry developments and the growth of our business and operations, are forward-looking statements. When used in this quarterly report, the words "may", "will", "could", "should", "expects", "plans' "anticipates", "believes", "estimates", "predicts", "projects", "potential", or "contemplate" or the negative of these terms or oth comparable terminology are intended to identify forward-looking statements, although not all forward-looking statements contain such words or expressions. The forward-looking statements in this quarterly report are primarily located in the material set forth under the headings "Management's Discussion and Analysis of Financial Condition and Results of Operations", "Risk Factors", and "Notes to Condensed Consolidated Financial Statements", but are found in other locations as well. These forward-looking statements generally relate to our plans, objectives and expectations for future operations and are based upon management's current estimates and projections of future results or trends. Although we believe that our plans and objectives reflected in or suggested by these forward-looking statements are reasonable, we may not achieve these plans or objectives. You should read this quarterly report completely and with the understanding that actual future results and developments may be materially different from what we expect due to a number of risks and uncertainties, many of which are beyond our control.

Specific factors that might cause actual results to differ from our expectations include, but are not limited to:

significant considerations, risks and uncertainties discussed in this quarterly report;

geothermal resource risk (such as the heat content, useful life and geological formation of the reservoir);

operating risks, including equipment failures and the amounts and timing of revenues and expenses;

financial market conditions and the results of financing efforts;

the impact of fluctuations in oil and natural gas prices on the energy price component under certain of our power purchase agreements (PPAs);

environmental constraints on operations and environmental liabilities arising out of past or present operations, including the risk that we may not have, and in the future may be unable to procure, any necessary permits or other environmental authorizations;

construction or other project delays or cancellations;

political, legal, regulatory, governmental, administrative and economic conditions and developments in the United States and other countries in which we operate;

the enforceability of the long-term PPAs for our power plants;

contract counterparty risk;

weather and other natural phenomena including earthquakes, volcanic eruption, drought and other nature disasters;

the impact of recent and future federal, state and local regulatory proceedings and changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, public policies and government incentives that support renewable energy and enhance the economic feasibility of our projects at the federal and state level in the United States and elsewhere, and carbon-related legislation;

changes in environmental and other laws and regulations to which our company is subject, as well as changes in the application of existing laws and regulations;

- current and future litigation;

- our ability to successfully identify, integrate and complete acquisitions;

- competition from other existing geothermal energy projects and new geothermal energy projects developed in the future, and from alternative electricity producing technologies;

- market or business conditions and fluctuations in demand for energy or capacity in the markets in which we operate;

- the direct or indirect impact on our company's business resulting from various forms of hostilities including the threat or occurrence of war, terrorist incidents or cyber-attacks or responses to such threatened or actual incidents or attacks, including the effect on the availability of and premiums on insurance;

- development and construction of the solar photovoltaic (Solar PV) projects , if any, may not materialize as planned;

- the effect of and changes in current and future land use and zoning regulations, residential, commercial and industrial development and urbanization in the areas in which we operate;

- the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2013 and any update contained herein and other risks and uncertainties detailed from time to time in our filings with the Securities and Exchange Commission (SEC); and

- other uncertainties which are difficult to predict or beyond our control and the risk that we may incorrectly analyze these risks and forces or that the strategies we develop to address them may be unsuccessful.

Investors are cautioned that these forward-looking statements are inherently uncertain. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results or outcomes may vary materially from those described herein. Other than as required by law we undertake no obligation to update forward-looking statements even though our situation may change in the future. Given these risks and uncertainties, readers are cautioned not to place undue reliance on such forward-looking statements.

The following discussion and analysis of our financial condition and results of operations should be read together with our condensed consolidated financial statements and related notes included elsewhere in this report and the "Risk Factors" section of our Annual Report on Form 10-K for the year ended December 31, 2013 and any updates contained herein as well as those set forth in our reports and other filings made with the SEC.

General

Overview

We are a leading vertically integrated company engaged primarily in the geothermal and recovered energy power business. We design, develop, build, sell, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, in most cases using equipment that we design and manufacture.

Our geothermal power plants include both power plants that we have built and power plants that we have acquired, while all of our recovered energy-based plants have been constructed by us. We conduct our business activities in two business segments:

The Electricity Segment — in this segment we develop, build, own and operate geothermal and recovered energy-based power plants in the United States and geothermal power plants in other countries around the world, and sell the electricity they generate; and

The Product Segment — in this segment we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation, remote power units and other power generating units and provide services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy-based power plants.

Both our Electricity Segment and Product Segment operations are conducted in the United States and throughout the world. Our current generating portfolio includes geothermal plants in the United States, Guatemala and Kenya, as well as recovered energy generation plants in the United States.

For the nine months ended September 30, 2014, our total revenues increased by 2.0% (from $402.3 million to $410.3 million) over the corresponding period in 2013.

For the nine months ended September 30, 2014, Electricity Segment revenues were $289.0 million, compared to $245.0 million for the nine months ended September 30, 2013, an increase of 18.0%, while Product Segment revenues for the nine months ended September 30, 2014 were $121.3 million, compared to $157.3 million during the nine months ended September 30, 2013, a decrease of 22.9%.

During the nine months ended September 30, 2014 and 2013, our consolidated power plants generated 3,269,048 megawatt hours (MWh) and 3,092,482 MWh, respectively, an increase of 5.7% with the majority of such increase due to new power plants that came online in the past year.

For the nine months ended September 30, 2014, our Electricity Segment represented approximately 70.4% of our total revenues, while our Product Segment represented approximately 29.6% of our total revenues. For the nine months ended September 30, 2013, our Electricity Segment represented approximately 60.9% of our total revenues, while our Product Segment represented approximately 39.1% of our total revenues.

For the nine months ended September 30, 2014, approximately 66.3% of our Electricity Segment revenues were derived from PPAs with fixed energy rates which are not affected by fluctuations in energy commodity prices. We have variable price PPAs in California and Hawaii, which provide for payments based on the local utilities' avoided cost, which is the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others, as follows:

The energy rates under the SO#4 PPAs in California for each of the Ormesa complex, the Heber 1 and Heber 2 power plants in the Heber complex and the G2 power plant in the Mammoth complex, change primarily based on fluctuations in natural gas prices; and

The prices paid for the electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii change primarily due to variations in the price of oil.

We have reduced our exposure to fluctuations in the price of oil until December 31, 2014 and in the price of natural gas until March 31, 2015, by entering into derivatives transactions. In the three and nine months ended September 30, 2014, we recorded a gain of $4.0 million and $1.3 million, respectively, in Electricity Segment revenues related to these transactions.

To comply with obligations under their respective PPAs, certain of our project subsidiaries are structured as special purpose, bankruptcy remote entities and their assets and liabilities are ring-fenced, and such assets are not generally available to pay our debt (other than debt at the respective project subsidiary level). However, these project subsidiaries are allowed to pay dividends and make distributions to us of all available and unrestricted cash flows generated by their assets.

Electricity Segment revenues are also subject to seasonal variations and can be affected by higher-than-average ambient temperatures, as described below under “Seasonality”. In addition, the revenues we report in our financial statements may show more variation due to our increased use of derivatives in connection with our variable price PPAs and the accounting principles associated with our use of those derivatives.

Revenues attributable to our Product Segment are based on the sale of equipment, engineering, procurement and construction (EPC) contracts and the provision of various services to our customers. These revenues may vary from period to period because of the timing of our receipt of purchase orders and the progress of our execution of each project.

Our management assesses the performance of our two segments of operation differently. In the case of our Electricity Segment, when making decisions about potential acquisitions or the development of new projects, we typically focus on the internal rate of return of the relevant investment, technical and geological matters and other business considerations. We evaluate our operating power plants based on revenues and expenses, and our projects that are under development based on costs attributable to each such project. We evaluate the performance of our Product Segment based on the timely delivery of our products, performance quality of our products, revenues and expenses and costs actually incurred to complete customer orders compared to the costs originally budgeted for such orders.

Recent Developments

The most significant developments in our company and business since January 1, 2014 are described below:

On November 3, 2014, we, through our majority owned subsidiary (the Project Company), signed a 25-year PPA with Kenya Power and Lightning Co. Ltd. (KPLC) and a project implementation and steam supply agreement (PISSA) with Geothermal Development Company (GDC) for the 35MW Menengai geothermal project in Kenya. Under the PISSA agreement, the Project Company will finance, design, construct, install, operate and maintain the Menengai steam plant on a build-own-operate (BOO) basis for 25 years. GDC, which is wholly owned by the Government of Kenya, will develop the geothermal resource, supply the steam for conversion to electricity and maintain the geothermal field through the term of the agreement. The Project Company expects to start construction upon financial closing.

On November 3, 2014, we, through our wholly owned subsidiary, signed a $22.3 million engineering, procurement and construction (EPC) agreement with the Utah Associated Municipal Power System (UAMPS). We will install an air-cooled Ormat Energy Converter (OEC) at the Kern River Transmission Company’s Veyo natural gas compressor station in Southern Utah. The recovered energy generation (REG) project will generate power using heat that would have otherwise gone waste.

On September 30, 2014, we repaid in full the outstanding amount of approximately $30.0 million loan with EIG Global Project Fund II, Ltd. (formerly TCW). The $42.0 million loan was signed in 2009 to refinance Ormat's investment in the 20 MW Amatitlan geothermal power plant located in Guatemala, of which $12.0 million was previously paid per the loan agreement. The loan was scheduled to mature on June 15, 2016 and carried an interest rate of 9.83%. This repayment resulted in a one-time charge to interest expense of approximately $1.1 million. We are negotiating a new financing agreement that we believe will contain improved terms.

On August 29, 2014, we announced the signing of a $140.0 million loan under the OFC 2 senior secured notes to finance the construction of the McGinness Hills Phase 2 project in Nevada. This drawdown is the last tranche under the Note Purchase Agreement with John Hancock Life Insurance Company (USA) and guaranteed by the U.S. Department of Energy’s Loan Programs Office in accordance with and subject to the Department’s Loan Guarantee Program under Section 1705 of Title XVII of the Energy Policy Act of 2005. The $140.0 million loan, which matures in December 2032, carries a 4.61% coupon with principal to be repaid on a quarterly basis. The OFC 2 Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated “BBB” by Standard & Poor’s. The plant is expected to come on line in the first quarter of 2015, bringing the complex’s total capacity to approximately 70 MW. We have a contract with NV Energy to sell energy produced at McGinness Hills through December 2032.

On August 5, 2014, we signed a definitive Purchase and Sale Agreement with Alternative Earth Resources Inc. (AER), pursuant to which we paid $1.5 million in cash and (i) purchased AER's (a) 50% interest in Crump Geyser and (b) North Valley geothermal project assets and (ii) obtained an option, exercisable over a four-year period, to purchase certain of AER's New Truckhaven geothermal.

On July 1, 2014, Mr. Isaac Angel assumed the CEO position. He succeeded Mrs. Yehudit (Dita) Bronicki, who announced her retirement in November 2013. Mrs. Bronicki continues to serve as a Director of Ormat in a non-executive capacity. In addition Mr. Gillon Beck stepped down from his position of Chairman of the Board of Directors of the Company effective June 30, 2014 and Mr. Yoram Bronicki assumed the position of Chairman. Mr. Beck continues to serve as a director of the Company. Upon assuming the position of the Chairman of the Board, Mr. Yoram Bronicki relinquished his position as President and Chief Operating Officer of the Company.

On May 23, 2014, we announced the closing of the $1.17 billion financing agreements entered into by the Sarulla consortium for the 330-megawatt (MW) project in North Sumatra in Indonesia. The Japan Bank for International Cooperation (JBIC), the Asian Development Bank and six commercial banks provided the Sarulla project construction and term loans under a limited recourse financing package backed by political risk guarantees from JBIC. The consortium expects the first phase of operations to commence in 2016. The remaining two phases of operations are scheduled to commence within 18 months thereafter. We will supply our Ormat Energy Converters to the power plants and we added the $254.0 million supply contract to our Product Segment backlog. According to the current project plan, we started to recognize revenue from the project during the third quarter of 2014 and will continue to recognize revenues over the course of the next three to four years.

On March 26, 2014, we signed an agreement with RET Holdings, LLC to sell the Heber Solar project in Imperial County, California for $35.25 million. We received the first payment of $15.0 million in the first quarter and the second payment for the remaining $20.25 million was paid in the second quarter of 2014. We recognized pre-tax gain of $7.6 million in the second quarter of 2014.

On February 4, 2014, we announced that we successfully completed construction and reached commercial operation of Plant 3 in the Olkaria III geothermal power plant complex in Kenya. With Plant 3 online, the complex's total generation capacity has increased to 110 MW. The power generated by the Olkaria III complex is sold under a 20-year PPA with KPLC. On November 25, 2013, we announced that we drew down the remaining $45.0 million comprising Tranche III of the previously announced $310.0 million project finance facility with OPIC.

On January 23, 2014, we announced that we successfully completed the scope of work needed to bring the Mammoth G1 geothermal power plant in Mono County, California to full capacity. The 6 MW plant reached commercial operation under the new PPA with Pacific, Gas and Electric (PG&E) that allows for hourly energy deliveries of up to 7.5 MW and, as of December 26, 2013, it received the full commercial rate defined in the PPA.

On January 22, 2014, we announced that one of our wholly owned subsidiaries signed an amendment to the PPA with INDE for the Zunil geothermal power plant in Guatemala, which extends the term of the PPA from 2019 to 2034. The amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to Ormat for the term of the amended PPA in exchange for a tariff increase. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant and to acquire a three percent equity interest therein.

On January 6, 2014, we announced that we completed the construction of the Don A. Campbell geothermal power plant in Mineral County, Nevada. The plant is currently producing at full generating capacity of 16 MW and performing as expected. The Don A. Campbell facility, formerly Wild Rose, receives a full rate of $99.0 per MWh with no annual escalation under the terms of the PPA, signed in April 2013, with Southern California Public Power Authority (SCPPA). SCPPA resells the power from the Don A. Campbell geothermal power plant to the Los Angeles Department of Water and Power (LADWP) and Burbank Water and Power through NV Energy Inc.'s transmission system.

Trends and Uncertainties

The geothermal industry in the United States has historically experienced significant growth followed by a consolidation of owners and operators of geothermal power plants. During the 1990s, growth and development in the geothermal industry occurred primarily in foreign markets and only minimal growth and development occurred in the United States. Since 2001, there has been increased demand for energy generated from geothermal resources in the United States as costs for electricity generated from geothermal resources have become more competitive. Recently, much of this is attributable to legislative and regulatory requirements and incentives, such as state renewable portfolio standards and federal tax credits. The American Recovery and Reinvestment Act of 2009 (ARRA) further encourages the use of geothermal energy through production tax credits (PTCs) or investment tax credits (ITCs) as well as cash grants (which are discussed in more detail in the section entitled "Government Grants and Tax Benefits" below). In response, the geothermal industry in the United States has seen a wave of new entrants and, over the last several years, consolidation involving smaller developers. We believe that the future demand for energy generated from geothermal and other renewable resources in the United States will be driven by further commitment and implementation of renewable portfolio standards as well as the introduction of additional tax incentives. The trends that from time to time impact our operations are subject to market cycles.

Although other trends, factors and uncertainties may impact our operations and financial condition, including many that we do not or cannot foresee, we believe that our results of operations and financial condition for the foreseeable future will be primarily affected by the following trends, factors and uncertainties:

- We expect to continue to generate the majority of our revenues from our Electricity Segment through the sale of electricity from our power plants. All of our current revenues from the sale of electricity are derived from payments under long-term PPAs related to fully-contracted power plants. We also intend to continue to pursue opportunities as they arise in our recovered energy business, in the Solar PV sector and in other forms of clean energy.

- Our focus continues to be organic growth through exploration, development, construction of new projects and enhancements of existing power plants along with increasing operational efficiency of our operating portfolio. We expect that our investment in organic growth will increase our total generating capacity, consolidated revenues and operating income attributable to our Electricity Segment from year to year. In addition, we routinely look at acquisition opportunities.

- The continued awareness of climate change may result in significant changes in the business and regulatory environments, which may create business opportunities for us. In 2011, the first phase of the Environmental Protection Agency (EPA) "Tailoring Rule" took effect. The Tailoring Rule sets thresholds addressing the applicability of the permitting requirements under the Clean Air Act's Prevention of Significant Deterioration and Title V programs to certain major sources of GHG emissions. On June 23, 2014, the United States Supreme Court issued its decision in *Utility Air Regulatory Group v. Environmental Protection Agency et al.*, No. 12-1146, in part addressing the Tailoring Rule. As a result of this decision, the EPA can no longer require stationary sources of greenhouse gas emissions to comply with requirements under the Clean Air Act's Prevention of Significant Deterioration and Title V programs solely because of emissions of greenhouse gases. Since the court also held that the EPA lacked the authority to interpret the Clean Air Act and issue the Tailoring Rule, the EPA must formally adopt thresholds triggering application of the Clean Air Act's Prevention of Significant Deterioration and Title V programs to stationary sources of greenhouse gas emissions that are subject to these programs in any event because of emissions of conventional pollutants. Different states have begun examining the effect of this decision to their applicable air emissions regulations. In addition to future establishment of these thresholds, federal legislation or additional federal regulations addressing climate change may be enacted.

In June 2013 President Barack Obama announced a new national climate action plan, directing the EPA to complete new carbon dioxide pollution standards for both new and existing power plants. EPA released proposed rules for new fossil fuel-fired power plants in September 2013 and from existing fossil fuel-fired power plants in June 2014. In the Clean Power Plan proposal states identify a path forward using either current or new electricity production and pollution control policies to meet the goals of the proposed program including cutting carbon emission from the power sector by 30% below 2005 levels nationwide by 2030. In addition, several states and regions are already addressing legislation to reduce GHG emissions. For example, California's state climate change law, AB 32, which was signed into law in September 2006, regulates most sources of GHG emissions and aims to reduce GHG emissions to 1990 levels by 2020. On October 20, 2011 the CARB adopted cap-and-trade regulations to reduce California's greenhouse gas emissions under AB 32. In addition to California, twenty U.S. states have set GHG emissions reduction targets and two states have reduction goals. Regional initiatives, such as the Western Climate Initiative (which includes California and four Canadian provinces) and the Midwest GHG Reduction Accord (which includes six U.S. states and one Canadian province), are also being developed to reduce GHG emissions and develop trading systems for renewable energy credits. In the United States, approximately 40 states have adopted RPS, renewable portfolio goals, or similar laws requiring or encouraging electric utilities in such states to generate or buy a certain percentage of their electricity from renewable energy sources or recovered heat sources. On April 12, 2011, the California Senate Bill X1-2 (SBX1-2) was signed into law, and increased California's RPS to 33% by December 31, 2020 and instituted a tradable REC program. SBX1-2 was expected to foster a liquid tradable REC market and lead to more creative off-take arrangements. Although we cannot predict at this time whether the tradable REC program under SBX1-2 and its implementing regulations will have a significant impact on our operations or revenue, it may facilitate additional options when negotiating PPAs and selling electricity from our projects.

In June 2013, the Nevada state legislature passed three bills that were signed by Nevada's Governor and are expected to support renewable energy development in the state. Senate bill (SB) No. 123 calls for the retirement or elimination of not less than 800 MW of coal-fired electric generating capacity on or before December 31, 2019 and the construction or acquisition of, or contracting for, 350 MW of electric generating capacity from renewable energy facilities. Senate bill 252 revises provisions relating to the renewable portfolio standard by removing energy efficiency, solar multipliers, and station usage from generating portfolio energy credits. Finally, Assembly Bill (AB) No.239 Revised Statutes 701A.340 defines geothermal energy as renewable energy for purposes of tax abatements and makes geothermal projects eligible for partial sales and property tax abatements, with property tax abatements for a period of twenty years and local sales and use tax abatements for three years. In September 26, 2014 Governor Brown signed into a law Assembly Bill No. 2363 (AB-2363), which requires the California Public Utilities Commission to adopt, by rulemaking, by December 31, 2015, a methodology for determining the costs of integrating eligible renewable energy resources

Outside of the United States, in November 2012, the U.S., Brunei, and Indonesia formed the Asia-Pacific comprehensive partnership and President Obama announced the allocation of $6.0 billion for green energy development in Asia. Also, on June 30, 2013, President Obama announced the "Power Africa" initiative pursuant to which the United States will invest $7.0 billion in Sub-Saharan Africa over the following five years, with the aim of doubling access to power. The Sub-Sahara Africa includes three countries (Ethiopia, Kenya and Tanzania) that have large geothermal potential as well as operating geothermal power plants. We accelerated our efforts to expand business development activities in those areas by, among other things, participating in new applicable bids. In addition, we expect that a variety of governmental initiatives will create new opportunities for the development of new projects, as well as create additional markets for our products. These initiatives include the award of long-term contracts to independent power generators, the creation of competitive wholesale markets for selling and trading energy, capacity and related energy products and the adoption of programs designed to encourage "clean" renewable and sustainable energy sources.

- In the Electricity Segment, we expect competition from the wind and solar power generation industry to continue. While we believe the expected demand for renewable energy will be large enough to accommodate increased competition, any such increase and the amount of renewable energy under contract may contribute to a reduction in electricity prices. Despite increased competition from the wind and solar power generation industry, we believe that base load electricity, such as geothermal-based energy, will continue to be an important source of renewable energy in areas with commercially viable geothermal resource. Also, geothermal power plants positively impact electrical grid stability and provide valuable ancillary services because of their base load nature while the intermittent renewables create integration costs. In the geothermal industry, we are experiencing a notable decrease in competition, specifically in the acquisition of geothermal leases. The reduced level of competition has contributed to a decrease in lease costs.

- In the Product Segment, we expect increased competition from binary power plant equipment suppliers including the major steam turbine manufacturers. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity, an increase in competition may impact our ability to secure new purchase orders from potential customers. The increased competition may also lead to a reduction in the prices that we are able to charge for our binary equipment, which in turn may impact our profitability.

- The changing natural gas landscape, the resulting effect on natural gas pricing (in either direction) and the corresponding implications for electric utilities and other producers of electricity in terms of planning for and choosing a source of fuel, will affect the pricing under our PPAs that have short run avoided cost (SRAC) pricing, as described below.

- The 38 MW Puna complex has three PPAs, of which the 25 MW PPA has a monthly variable energy rate based on the local utility's avoided costs. A decrease in the price of oil will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from oil, which will result in a reduction of the energy rate that we may charge under this PPA. In order to reduce our economic exposure to oil price we signed a fixed rate PPAs for the rest of the complex and we are currently negotiating a fixed price for the 25 MW PPA as well. In the meantime, we have entered into derivatives contracts to reduce our exposure to fluctuations in the energy rate caused by fluctuations in oil prices through December 31, 2014. Our use of derivative instruments for this purpose has increased, and likely will continue to be used to manage our economic exposure.

- Our Puna Complex is located in Puna District in the Big Island, Hawaii, which is the general area that has been impacted by the eruption of K"lauea active volcano in June 27, 2014 and the resulting lava flow and continuing volcanic activity since then. Our power plants at the Puna Complex were not themselves directly affected by the volcanic eruption and the resulting lava flow. However, the uncertainties regarding the potential impact of the lava flow on the transmission lines owned and maintained by HELCO (our power purchaser) necessitated contingency planning and cooperation with HELCO in anticipation of a possible loss of transmission capacity. As of the date of this Quarterly Report on Form 10-Q, HELCO has implemented several measures to protect the two transmission lines over which power generated by the Puna complex is transmitted to the grid from the extreme heat generated by the lava flow passing through and around the transmission poles, our power plant was not effected from the Lava flow and the transmission lines are operating at regular capacity. It is impossible to predict whether the lava flow or other new or recurring volcanic activity may subsequently adversely impact the operation of our Puna complex and the operational integrity of the transmission poles and the transmission lines. Our Puna complex revenues comprise capacity payments and energy payments from HELCO. In the event of declared Force Majeure, HELCO is required to continue to make capacity payments but is not required to make energy payments to the extent the force majeure event precludes us from delivering, or HELCO from taking, the energy. Loss of energy payments under our Puna PPAs would have an adverse effect on our financial performance. Revenues generated by Puna comprised 9.2% of our total revenues in 2013.

- We had PPAs for the Ormesa Mammoth and Heber complexes for a total of 161 MW that were fixed until May 1, 2012. Thereafter, the energy price component under these PPAs changed from a fixed rate to a variable rate based on SRAC pricing that is impacted by fluctuations in natural gas prices. In 2013, we signed new fixed rate PPAs that reduced our current exposure to SRAC by 18 MW and by additional 44 MW in 2016. We have entered into derivative transactions at a fixed price of $4.07 per MMbtu for the year 2014 to reduce further our exposure to fluctuations in natural gas prices through December 31, 2014 and $4.95 per MMbtu for the period from January 1, 2015 until March 31, 2015. Our use of derivative instruments for this purpose has increased, and likely will continue to be used to manage our economic exposure.

- The viability of a geothermal resource depends on various factors such as the resource temperature, the permeability of the resource (i.e., the ability to get geothermal fluids to the surface) and operational factors relating to the extraction and injection of the geothermal fluids. Such factors, together with the possibility that we may fail to find commercially viable geothermal resources in the future, represent significant uncertainties that we face in connection with our growth expectations.

- As our power plants (including their respective well fields) age, they may require increased maintenance with a resulting decrease in their availability, potentially leading to the imposition of penalties if we are not able to meet the requirements under our PPAs as a result of any decrease in availability.

- Our foreign operations are subject to significant political, hostility, economic and financial risks, which vary by country. As of the date of this report, those risks include security conditions in Israel, the partial privatization of the electricity sector in Guatemala and the political uncertainty currently prevailing in some of the countries in which we operate as further described in the “Risk Factors” section of our annual report on Form 10-K for the year ended December 31, 2013. Although we maintain among other things political risk insurance for most of our investments in foreign power plants to mitigate these risks, insurance does not provide complete coverage with respect to all such risks.

- The Sarulla 330 MW project was released for construction and we started to recognize our first product segment revenues in the quarter ended September 30, 2014, under the supply contract we signed with the EPC contractor. Going forward we expect to derive significant revenues from the supply contract. Additional income is expected from our 12.75% equity investment in the Sarulla consortium. The Sarulla project's future operations may be impacted by various factors which we do not control given our minority position in the consortium, as well as other factors discussed under the heading "risk factors" in our annual report on form 10-K for the year ended 2013.

- FERC is allowed under PURPA terminate, upon the request of a utility, the obligation of electric utilities to purchase the output of a Qualifying Facility if FERC finds that there is an accessible competitive market for energy and capacity from the Qualifying Facility. The legislation does not affect existing PPAs. We do not expect this change in law to affect our U.S. power plants significantly, as all of our current PPAs are long-term. FERC has granted the California investor owned utilities a waiver of the mandatory purchase obligations from Qualifying Facilities above 20 MW. If the utilities in the regions in which our domestic power plants operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from us upon termination of the existing PPA, which could have an adverse effect on our revenues.

Revenues

We generate our revenues from the sale of electricity from our geothermal and recovered energy-based power plants; the design, manufacture and sale of equipment for electricity generation; and the construction, installation and engineering of power plant equipment.

Revenues attributable to our Electricity Segment are derived from the sale of electricity from our power plants pursuant to long-term PPAs. While approximately 66.3% of our Electricity revenues for the nine months ended September 30, 2014 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. Our 143MW California SO#4 PPAs are subject to the impact of fluctuations in natural gas prices whereas the prices paid for electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii are impacted by the price of oil. Accordingly, our revenues from those power plants may fluctuate. In 2013 and 2014, we entered into derivative transactions in an attempt to reduce our exposure to fluctuations in the prices of oil from Puna's PPAs until December 31, 2014 and natural gas from the California SO#4 PPAs until March 31, 2015.

Our Electricity Segment revenues are also subject to seasonal variations, as more fully described under "Seasonality" below.

Our PPAs generally provide for energy payments alone, or energy and capacity payments. Generally, capacity payments are payments calculated based on the amount of time that our power plants are available to generate electricity. Some of our PPAs provide for bonus payments in the event that we are able to exceed certain target capacity levels and the potential forfeiture of payments if we fail to meet certain minimum target capacity levels. Energy payments, on the other hand, are payments calculated based on the amount of electrical energy delivered to the relevant power purchaser at a designated delivery point. The rates applicable to such payments are either fixed (subject, in certain cases, to certain adjustments) or are based on the relevant power purchaser's avoided costs. Our more recent PPAs generally provide for energy payments alone with an obligation to compensate the off-taker for its incremental costs as a result of shortfalls in our supply.

Revenues attributable to our Product Segment fluctuate between periods, mainly based on our ability to receive customer orders and the status and timing of such orders. Larger customer orders for our products are typically the result of our participating in, and winning, tenders or requests for proposals issued by potential customers in connection with projects they are developing. Such projects often take a significant amount of time to design and develop and are subject to various contingencies, such as the customer's ability to raise the necessary financing for a project. Consequently, we are generally unable to predict the timing of such orders for our products and may not be able to replace existing orders that we have completed with new ones. As a result, revenues from our Product Segment fluctuate (sometimes, extensively) from period to period.

The following table sets forth a breakdown of our revenues for the periods indicated:

	Revenues (in thousands)				**% of Revenues for Period Indicated**			
	Three Months Ended		**Nine Months Ended**		**Three Months Ended**		**Nine Months Ended**	
	September 30,		**September 30,**		**September 30,**		**September 30,**	
	2014	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Revenues:								
Electricity	$102,506	$88,994	$289,015	$245,005	73.1 %	68.1 %	70.4 %	60.9 %
Product	37,736	41,755	121,266	157,329	26.9	31.9	29.6	39.1
Total	$140,242	$130,749	$410,281	$402,334	100.0%	100.0%	100.0%	100.0%

The following table sets forth the geographic breakdown of the revenues attributable to our Electricity and Product Segments for the periods indicated:

	Revenues (in thousands)				**% of Revenues for Period Indicated**			
	Three Months Ended		**Nine Months Ended**		**Three Months Ended**		**Nine Months Ended**	
	September 30,		**September 30,**		**September 30,**		**September 30,**	
	2014	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
Electricity Segment:								
United States	$72,907	$66,073	$202,860	$184,777	71.1 %	74.2 %	70.2 %	75.4 %
Foreign	29,599	22,921	86,155	60,228	28.9	25.8	29.8	24.6
Total	$102,506	$88,994	$289,015	$245,005	100.0%	100.0%	100.0%	100.0%
Product Segment:								
United States	$28,797	$13,832	$69,065	$43,696	76.3 %	33.1 %	57.0 %	27.8 %
Foreign	8,939	27,923	52,201	113,633	23.7	66.9	43.0	72.2
Total	$37,736	$41,755	$121,266	$157,329	100.0%	100.0%	100.0%	100.0%

Seasonality

The prices paid for the electricity generated by some of our domestic power plants pursuant to our PPAs are subject to seasonal variations. The prices (mainly for capacity) paid for electricity under the PPAs with Southern California Edison and Pacific Gas & Electric in California for the Heber 1 and 2 power plants in the Heber complex, the Mammoth complex, the Ormesa complex, and the North Brawley power plant are higher in the months of June through September. As a result, we receive, and expect to continue to receive in the future, higher revenues during such months. In the winter, our power plants produce more energy principally due to the lower ambient temperature, which has a favorable impact on our energy revenues. However, the higher payments payable by Southern California Edison and Pacific Gas & Electric Company in the summer months have a more significant impact on our revenues than that of the higher energy revenues generally generated in winter due to increased efficiency. As a result, our electricity revenues are generally higher in the summer than in the winter.

Breakdown of Cost of Revenues

Electricity Segment

The principal cost of revenues attributable to our operating power plants includes operation and maintenance expenses comprised of salaries and related employee benefits, equipment expenses, costs of parts and chemicals, costs related to third-party services, lease expenses, royalties, startup and auxiliary electricity purchases, property taxes, insurance and, for some of our projects, purchases of make-up water for use in our cooling towers and also depreciation and amortization. In our California power plants, our principal cost of revenues also includes transmission charges and scheduling charges. Some of these expenses, such as parts, third-party services and major maintenance, are not incurred on a regular basis. This results in fluctuations in our expenses and our results of operations for individual power plants from quarter to quarter. Payments made to government agencies and private entities on account of site leases where plants are located are included in cost of revenues. Royalty payments, included in cost of revenues, are made as compensation for the right to use certain geothermal resources and are paid as a percentage of the revenues derived from the associated geothermal rights. Royalties constituted approximately 4.3% and 4.1% of Electricity Segment revenues for the nine months ended September 30, 2014 and 2013, respectively.

Product Segment

The principal cost of revenues attributable to our Product Segment includes materials, salaries and related employee benefits, expenses related to subcontracting activities, and transportation expenses. Sales commissions to sales representatives are included in selling and marketing expenses. Some of the principal expenses attributable to our Product Segment, such as a portion of the costs related to labor, utilities and other support services are fixed, while others, such as materials, construction, transportation and sales commissions, are variable and may fluctuate significantly, depending on market conditions. As a result, the cost of revenues attributable to our Product Segment, expressed as a percentage of total revenues, fluctuates. Another reason for such fluctuation is that in responding to bids for our products, we price our products and services in relation to existing competition and other prevailing market conditions, which may vary substantially from order to order.

Cash and Cash Equivalents

Our cash and cash equivalents, as of September 30, 2014 decreased to $42.5 million from $57.4 million as of December 31, 2013. This decrease was principally due to: (i) our use of $122.6 million during the nine months ended September 30, 2014 to fund capital expenditures; (ii) a net change in restricted cash and cash equivalents of $76.4 million; (iii) $12.9 million of cash used during the nine months ended September 30, 2014 to repurchase Ormat Funding LLC (OFC) Senior Secured Notes; (iv) net repayment of $83.9 million used under our revolving credit lines with commercial banks; (v) repayment of $80.2 million of long-term debt during the nine months ended September 30, 2014; (vi) $9.2 million of cash paid to noncontrolling interest; and (vii) $7.3 million cash dividend paid during the first three quarters of 2014. This decrease was partially offset by: (i) an additional $140.0 million of proceeds from the sale of Series C Senior Secured Notes in August 2014 by OFC 2 to finance a portion of the construction costs of Phase 2 of the McGinness Hills facility; (ii) $178.8 million derived from operating activities during the nine months ended September 30, 2014; (iii) cash grant of $27.4 million received from the U.S. Treasury under Section 1603 of the ARRA in the nine months ended September 30, 2014 relating to our Don A. Campbell geothermal power plant and our G1 refurbishment power plant at Mammoth Complex; and (iv) $35.3 million cash received during the nine months ended September 30, 2014 from the sale of the Heber Solar plant. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of September 30, 2014 was $625.8 million, as described below in "Liquidity and Capital Resources", of which we have utilized $396.6 million (including $360.6 million of letters of credit) as of September 30, 2014.

Critical Accounting Estimates and Assumptions

A comprehensive discussion of our critical accounting estimates and assumptions is included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section in our annual report on Form 10-K for the year ended December 31, 2013.

New Accounting Pronouncements

See Note 2 to our condensed consolidated financial statements set forth in Item 1 of this quarterly report for information regarding new accounting pronouncements.

Results of Operations

Our historical operating results in dollars and as a percentage of total revenues are presented below. A comparison of the different periods described below may be of limited utility primarily as a result of (i) our recent construction or disposition of new power plants and enhancement of acquired power plants and (ii) fluctuation in revenues from our Product Segment.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2014	**2013**	**2014**	**2013**
	(In thousands, except per share data)		**(In thousands, except per share data)**	
Statements of Operations Historical Data:				
Revenues:				
Electricity	$102,506	$88,994	$289,015	$245,005
Product	37,736	41,755	121,266	157,329
	140,242	130,749	410,281	402,334
Cost of revenues:				
Electricity	61,727	61,356	186,083	175,085
Product	23,040	29,637	75,307	110,335
	84,767	90,993	261,390	285,420
Gross margin:				
Electricity	40,779	27,638	102,932	69,920
Product	14,696	12,118	45,959	46,994
	55,475	39,756	148,891	116,914
Operating expenses:				
Research and development expenses	250	838	395	3,446
Selling and marketing expenses	4,258	2,575	10,853	17,861
General and administrative expenses	7,179	6,546	20,847	20,264
Write-off of unsuccessful exploration activities	—	—	8,107	—
Operating income	43,788	29,797	108,689	75,343
Other income (expense):				
Interest income	35	742	236	870
Interest expense, net	(22,494)	(18,459)	(65,084)	(51,826)
Foreign currency translation and transaction gains (losses)	(2,946)	1,258	(3,639)	3,844
Income attributable to sale of tax benefits	5,487	5,027	18,334	14,342
Gain from sale of property, plant and equipment	—	—	7,628	—
Other non-operating income, net	243	137	649	1,583
Income before income taxes and equity in income (losses) of investees	24,113	18,502	66,813	44,156
Income tax provision	(6,444)	(5,201)	(17,731)	(15,028)
Equity in losses of investees	(899)	(158)	(1,210)	(149)
Income from continuing operations	16,770	13,143	47,872	28,979

Discontinued operations:				
Income from discontinued operations (including gain on disposal of $0, $0, $0 and $3,646, respectively)	—	—	—	5,311
Income tax provision	—	—	—	(614)
Total income from discontinued operations	—	—	—	4,697
Net income	16,770	13,143	47,872	33,676
Net income attributable to noncontrolling interest	(256)	(193)	(670)	(600)
Net income attributable to the Company's stockholders	$16,514	$12,950	$47,202	$33,076
Earnings per share attributable to the Company's stockholders				
Basic:	$0.37	$0.29	$1.04	$0.62
Discontinued operations	—	—	—	0.10
Net income	$0.37	$0.29	$1.04	$0.72
Diluted:	$0.36	$0.28	$1.03	$0.62
Discontinued operations	—	—	—	0.10
Net income	$0.36	$0.28	$1.03	$0.72
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:				
Basic	45,690	45,438	45,594	45,433
Diluted	46,102	45,494	45,917	45,454

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Statements of Operations Percentage Data:				
Revenues:				
Electricity	73.1 %	68.1 %	70.4 %	60.9 %
Product	26.9	31.9	29.6	39.1
	100.0	100.0	100.0	100.0
Cost of revenues:				
Electricity	60.2	68.9	64.4	71.5
Product	61.1	71.0	62.1	70.1
	60.4	69.6	63.7	70.9
Gross margin:				
Electricity	39.8	31.1	35.6	28.5
Product	38.9	29.0	37.9	29.9
	39.6	30.4	36.3	29.1
Operating expenses:				
Research and development expenses	0.2	0.6	0.1	0.9
Selling and marketing expenses	3.0	2.0	2.6	4.4
General and administrative expenses	5.1	5.0	5.1	5.0
Write-off of unsuccessful exploration activities	0.0	0.0	2.0	0.0
Operating income	31.2	22.8	26.5	18.7
Other income (expense):				
Interest income	0.0	0.6	0.1	0.2
Interest expense, net	(16.0)	(14.1)	(15.9)	(12.9)
Foreign currency translation and transaction gains (losses)	(2.1)	1.0	(0.9)	1.0
Income attributable to sale of tax benefits	3.9	3.8	4.5	3.6
Gain from sale of property, plant and equipment	0.0	0.0	1.9	0.0
Other non-operating income, net	0.2	0.1	0.2	0.4
Income, before income taxes and equity in income (losses) of investees	17.2	14.2	16.4	11.0
Income tax provision	(4.6)	(4.0)	(4.3)	(3.7)
Equity in income (losses) of investees	(0.6)	(0.1)	(0.3)	0.0
Income from continuing operations	12.0	10.1	11.8	7.2
Discontinued operations:				
Income from discontinued operations (including gain on disposal of $0, $0, $0 and $3,646, respectively)	0.0	0.0	0.0	1.3
Income tax provision	0.0	0.0	0.0	(0.2)
Total income from discontinued operations	0.0	0.0	0.0	1.2
Net income	12.0	10.1	11.8	8.4
Net income attributable to noncontrolling interest	(0.2)	(0.1)	(0.2)	(0.1)
Net income attributable to the Company's stockholders	11.8 %	9.9 %	11.6 %	8.2 %

Comparison of the Three Months Ended September 30, 2014 and the Three Months Ended September 30, 2013

Total Revenues

Total revenues for the three months ended September 30, 2014 were $140.2 million, compared to $130.7 million for the three months ended September 30, 2013, which represented a 7.3% increase. This increase was attributable to our Electricity Segment, in which revenues increased by 15.2% over the corresponding period in 2013. This increase was partially offset due to a 9.6% decrease in our Product Segment revenues over the corresponding period in 2013.

Electricity Segment

Revenues attributable to our Electricity Segment for the three months ended September 30, 2014 were $102.5 million, compared to $89.0 million for the three months ended September 30, 2013, which represented a 15.2% increase in such revenues. This increase was primarily due to our Plant 3 at the Olkaria III complex in Kenya and our Don A. Campbell power plant in Nevada, which commenced commercial operations in January 2014 and December 2013, respectively. In addition, we recorded a net gain on derivative contracts on oil and natural gas prices of $4.0 million in the third quarter of 2014 compared to net loss of $0.3 million in the corresponding period in 2013.

Power generation in our power plants increased by 5.3% from 985,531 MWh in the three months ended September 30, 2013 to 1,037,272 MWh in the three months ended September 30, 2014 mainly due to the commencement of commercial operations of Plant 3 in the Olkaria III complex and the Don A. Campbell power plant. This increase was offset mainly due to lower load in the pipelines providing the heat to our REG power plants.

Product Segment

Revenues attributable to our Product Segment for the three months ended September 30, 2014 were $37.7 million, compared to $41.8 million for the three months ended September 30, 2013, which represented a 9.6% decrease. This decrease in our Product Segment revenues was primarily due to timing of revenue recognition and different product mix.

Total Cost of Revenues

Total cost of revenues for the three months ended September 30, 2014 was $84.8 million, compared to $91.0 million for the three months ended September 30, 2013, which represented a 6.8% decrease. This decrease was primarily due to the decrease in cost of revenues from our Product Segment. As a percentage of total revenues, our total cost of revenues for the three months ended September 30, 2014 was 60.4%, compared to 69.6% for the three months ended September 30, 2013.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the three months ended September 30, 2014 was $61.7 million, compared to $61.4 million for the three months ended September 30, 2013. As a percentage of total electricity revenues, our total cost of revenues attributable to our Electricity Segment for the three months ended September 30, 2014 was 60.2%, compared to 68.9% for the three months ended September 30, 2013. This decrease was mainly due to new power plants that came on line with lower operating expenses due to higher efficiency.

Product Segment

Total cost of revenues attributable to our Product Segment for the three months ended September 30, 2014 was $23.0 million, compared to $29.6 million for the three months ended September 30, 2013, which represented a 22.3% decrease. This decrease was primarily due to the decrease in Product Segment revenues, as discussed above. As a percentage of total Product Segment revenues, our total cost of revenues attributable to this segment for the three months ended September 30, 2014 was 61.1%, compared to 71.0% for the three months ended September 30, 2013. The decrease was mainly attributable to the different product mix and different margins in the various sales contracts we entered into for this segment during these periods.

Research and Development Expenses

Research and development expenses excluding grants from the U.S. Department of Energy were $0.3 million for the three months ended September 30, 2014, compared to $1.0 million for the three months ended September 30, 2013. Research and development expenses are net of grants from the U.S. Department of Energy in the amount of $0 and $0.2 million for the three months ended September 30, 2014 and 2013, respectively, related to the Enhanced Geothermal System project. Research and development expenses for the three months ended September 30, 2014 were $0.3 million, compared to $0.8 million for the three months ended September 30, 2013.

Selling and Marketing Expenses

Selling and marketing expenses for the three months ended September 30, 2014 were $4.3 million, compared to $2.6 million for the three months ended September 30, 2013. The increase was primarily due to higher sales commissions related to our Product Segment due to different commissions mix. Selling and marketing expenses for the three months ended September 30, 2014 constituted 3.0% of total revenues, compared to 2.0% for the three months ended September 30, 2013.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2014 were $7.2 million, compared to $6.5 million for the three months ended September 30, 2013. General and administrative expenses for the three months ended September 30, 2014 constituted 5.1% of total revenues, compared to 5.0% for the three months ended September 30, 2013.

Operating Income

Operating income for the three months ended September 30, 2014 was $43.8 million, compared to $29.8 million for the three months ended September 30, 2013. The increase in operating income was principally attributable to the increase in our gross margin in both our Electricity and Product segments as discussed above. Operating income attributable to our Electricity Segment for the three months ended September 30, 2014 was $32.4 million, compared to $20.7 million for the three months ended September 30, 2013. Operating income attributable to our Product Segment for the three months ended September 30, 2014 was $11.4 million, compared to $9.1 million for the three months ended September 30, 2013.

Interest Expense, Net

Interest expense, net for the three months ended September 30, 2014 was $22.5 million, compared to $18.5 million for the three months ended September 30, 2013. This increase was primarily due to: (i) a $1.1 million prepayment premium and write-off of financing expenses; (ii) an increase in interest expense related to two drawdowns (one for $140.0 million completed on August 29, 2014 under the long term OFC 2 Senior Secured Notes to finance McGinness Hills phase 2 and $45.0 million completed in November 2014 under new long term loan with OPIC), which replaced revolving lines of credit with lower interest rate; and (iii) a $1.0 million decrease related to interest capitalized to projects.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translation and transaction losses for the three months ended September 30, 2014 were $2.9 million, compared to gains of $1.3 million for the three months ended September 30, 2013. The loss was primarily due to foreign currency forward contracts that we entered into to hedge our exposure to the NIS during the three months ended September 30, 2014, which were not accounted for as hedge transactions, due to recent strengthening of the US dollar.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described in “OPC Transaction” and “ORTP Transaction”, each below) for the three months ended September 30, 2014 was $5.5 million, compared to $5.0 million for the three months ended September 30, 2013. This income represents the value of PTCs and taxable income or loss generated by OPC and ORTP and allocated to the investors in the amount of $1.7 million and $3.9 million, respectively, in the three months ended September 30, 2014, compared to $1.1 million and $3.9 million, respectively, in the three months ended September 30, 2013.

Income Taxes

Income tax provision for the three months ended September 30, 2014 was $6.4 million, compared to $5.2 million for the three months ended September 30, 2013. Our effective tax rate for the three months ended September 30, 2014 and 2013 was 26.7% and 28.1%, respectively. The effective tax rate differs from the statutory rate of 35% for the three months ended September 30, 2014, primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions.

Equity in losses of investee

Equity in losses of investee for the September 30, 2014 was $0.9 million, compared to $0.2 million for the September 30, 2013. Equity in losses of investee derived from our 12.75% ownership in the Sarulla project.

Net Income

Net income for the three months ended September 30, 2014 was $16.8 million, compared to $13.1 million for the three months ended September 30, 2013, which represents a 27.6% increase. The increase in net income of $3.7 million was principally attributable to a $14.0 million increase in operating income partially offset due to (i) a $4.0 million increase in interest expense, net, and (ii) a $4.2 million decrease in foreign currency translation and transaction gains; and (iii) a $1.2 million increase in income tax provision.

Comparison of the Nine Months Ended September 30, 2014 and the Nine Months Ended September 30, 2013

Total Revenues

Total revenues for the nine months ended September 30, 2014 were $410.3 million, compared to $402.3 million for the nine months ended September 30, 2013, which represented a 2.0% increase. This increase was attributable to our Electricity Segment, in which revenues increased by 18.0% over the corresponding period in 2013. This increase was offset due to a 22.9% decrease in our Product Segment over the corresponding period in 2013.

Electricity Segment

Revenues attributable to our Electricity Segment for the nine months ended September 30, 2014 were $289.0 million, compared to $245.0 million for the nine months ended September 30, 2013, which represented an 18.0% increase. This increase was primarily due to: (i) the commencement of operations of our Plant 2 and 3 at the Olkaria III complex in Kenya, which commenced commercial operations in May 2013 and January 2014, respectively, and our Don A. Campbell power plant in Nevada, which commenced commercial operations in December 2013; (ii) higher energy rates under the SO#4 contracts; and (iii) net gain on derivative contracts on oil and natural gas prices of $1.3 million in the nine months ended September 30, 2014, compared to net loss of $1.5 million in the corresponding period in 2013.

Power generation in our power plants increased by 5.7% from 3,092,482 MWh in the nine months ended September 30, 2013 to 3,281,785 MWh in the nine months ended September 30, 2014 mainly due to the commercial operations of Plant 2 and 3 in the Olkaria III complex and the Don A. Campbell power plant.

Product Segment

Revenues attributable to our Product Segment for the nine months ended September 30, 2014 were $121.3 million, compared to $157.3 million for the nine months ended September 30, 2013, which represented a 22.9% decrease. This decrease in our Product Segment revenues was primarily due to timing of revenue recognition and different product mix.

Total Cost of Revenues

Total cost of revenues for the nine months ended September 30, 2014 was $261.4 million, compared to $285.4 million for the nine months ended September 30, 2013, which represented an 8.4% decrease. This decrease was primarily due to the decrease in cost of revenues from our Product Segment. The decrease was partially offset due to an increase in cost of revenues from our Electricity Segment. As a percentage of total revenues, our total cost of revenues for the nine months ended September 30, 2014 was 63.7%, compared to 70.9% for the nine months ended September 30, 2013. This decrease was attributable to a decrease in cost of revenues as a percentage of total revenues, in both our Electricity and Product Segments, as further explained below.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the nine months ended September 30, 2014 was $186.1 million, compared to $175.1 million for the nine months ended September 30, 2013, which represented a 6.3% increase. This increase was primarily due to additional cost of revenues from the new power plants that commenced commercial operation in 2013 and 2014, as discussed above. As a percentage of total Electricity Segment revenues, the total cost of revenues attributable to our Electricity Segment for the nine months ended September 30, 2014 was 64.4%, compared to 71.5% for the nine months ended September 30, 2013. This decrease was mainly due to new power plants that came on line with lower operating expenses due to higher efficiency.

Product Segment

Total cost of revenues attributable to our Product Segment for the nine months ended September 30, 2014 was $75.3 million, compared to $110.3 million for the nine months ended September 30, 2013, which represented a 31.7% decrease. This decrease was primarily due to the decrease in Product Segment revenues as discussed above. As a percentage of total Product Segment revenues, our total cost of revenues attributable to the Product Segment for the nine months ended September 30, 2014 was 62.1%, compared to 70.1% for the nine months ended September 30, 2013. The decrease was mainly attributable to the different product mix and different margins in the various sales contracts we entered into for this segment during these periods.

39

Research and Development Expenses

Research and development expenses excluding grants from the U.S. Department of Energy were $0.9 million for the nine months ended September 30, 2014, compared to $4.7 million for the nine months ended September 30, 2013. Research and development expenses are net of grants from the U.S. Department of Energy in the amount of $0.5 million and $1.3 million for the nine months ended September 30, 2014 and 2013, respectively, related to the Enhanced Geothermal Systems project. Research and development expenses for the nine months ended September 30, 2014 were $0.4 million, compared to $3.4 million for the nine months ended September 30, 2013.

Selling and Marketing Expenses

Selling and marketing expenses for the nine months ended September 30, 2014 were $10.9 million, compared to $17.9 million for the nine months ended September 30, 2013. The decrease was primarily due to a one-time early termination fee in the amount of $9.0 million we paid to SCE in the first quarter of 2013 to terminate PPAs for the G1 and G3 power plants in the Mammoth complex. Excluding the one-time termination fee, selling and marketing expenses for the nine months ended September 30, 2014 constituted 2.6% of total revenues for such period, compared to 2.2% for the nine months ended September 30, 2013.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2014 and 2013 were $20.8 million, compared to $20.3 million for the nine months ended September 30, 2013. General and administrative expenses for the nine months ended September 30, 2014 and 2013 constituted 5.1% of our total revenues for such period.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the nine months ended September 30, 2014 was $8.1 million. This represented the write-off of exploration costs related to our exploration activities in the Wister site in California, which we determined in the second quarter of 2014 would not support commercial operation. There were no write-offs of unsuccessful exploration activities for the nine months ended September 30, 2013.

Operating Income

Operating income for the nine months ended September 30, 2014 was $108.7 million, compared to $75.3 million for the nine months ended September 30, 2013, an increase of 44.3%. The increase in operating income was principally attributable to (i) the increase in our gross margin in our Electricity Segment and (ii) a one-time early termination fee of $9.0 million recorded in the first quarter of 2013, both as discussed above. This increase was partially offset due to a write-off of unsuccessful exploration activities, as discussed above. Operating income attributable to our Electricity Segment for the nine months ended September 30, 2014 was $72.8 million, compared to $42.1 million for the nine months ended September 30, 2013. Operating income attributable to our Product Segment for the nine months ended September 30, 2014 was $35.8 million, compared to $33.3 million for the nine months ended September 30, 2013.

Interest Expense, Net

Interest expense, net for the nine months ended September 30, 2014 was $65.1 million, compared to $51.8 million for the nine months ended September 30, 2013, which represented a 25.6% increase. This increase was primarily due to: (i) a $1.7 million prepayment premium and write-off of financing expenses; (ii) the conversion in July 2013 of OPIC interest loans from floating interest rate to fixed interest rate; and (iii) a $4.5 million decrease related to interest capitalized to projects.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translation and transaction losses for the nine months ended September 30, 2014 were $3.6 million, compared to gains of $3.8 million for the nine months ended September 30, 2013. The loss was primarily due to foreign currency forward contracts that we entered into to hedge our exposure to the NIS for the nine months ended September 30, 2014, which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described in “OPC Transaction” and “ORTP Transaction”, each below) for the nine months ended September 30, 2014 was $18.3 million, compared to $14.3 million for the nine months ended September 30, 2013. This income represents the value of PTCs and taxable income or loss generated by OPC and ORTP and allocated to the investors in the amount of $4.9 million and $13.4 million, respectively, in the nine months ended September 30, 2014, compared to $4.0 million and $10.3 million, respectively, in the nine months ended September 30, 2013. This increase was primarily attributable to an additional payment we received in the three months ended March 31, 2014, in the amount of $2.2 million related to the ORTP transaction which represented 25% of the value of PTC’s generated by the portfolio over time, compared to the original forecast.

Gain from Sale of Property, Plant and Equipment

Gain from sale of property, plant and equipment for the nine months ended September 30, 2014 was $7.6 million. This gain relates to the sale of the Heber Solar project in Imperial County, California for $35.25 million in the first quarter of 2014. We received the first payment of $15.0 million in the first quarter of 2014, and the second payment for the remaining $20.25 million in the second quarter of 2014. We recognized the gain in the second quarter of 2014. There was no gain from sale of power plant in the nine months ended September 30, 2013.

Income Taxes

Income tax provision for the nine months ended September 30, 2014 was $17.7 million, compared to $15.0 million for the nine months ended September 30, 2013. Our effective tax rate for the nine months ended September 30, 2014 and 2013, was 26.5% and 34.0%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the nine months ended September 30, 2014, primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions.

Equity in losses of investee

Equity in losses of investee for the nine months ended September 30, 2014 was $1.2 million, compared to $0.1 million for the nine months ended September 30, 2013. Equity in losses of investee derived from our 12.75% ownership in the Sarulla project.

Income from Continuing Operations

Income from continuing operations for the nine months ended September 30, 2014 was $47.9 million, compared to $29.0 million for the nine months ended September 30, 2013 an increase of 65.2%. The increase in income from continuing operations of $18.9 million was principally attributable to: (i) a $33.3 million increase in operating income; (ii) a $7.6 million gain on sale of property, plant and equipment; and (iii) $4.0 million increase in income attributable to sale of tax benefits all as discussed above. This increase was partially offset by: (i) a $13.3 million increase in interest expense; (ii) a $7.5 million decrease in foreign currency translation and transaction gains; and (iii) a $2.7 million increase in income tax provision.

Discontinued Operations

In May 2013, our wholly owned subsidiary sold its interest in MPC, the operator of the Momotombo geothermal power plant in Nicaragua, to a private company for $7.8 million, approximately one year before the scheduled termination of the concession agreement with the Nicaraguan owner. As a result, we recorded an after-tax gain on sale of $3.6 million in the nine months ended September 30, 2013. The operations of the MPC for the nine months ended September 30, 2013 have been included in discontinued operations. Discontinued operations for the nine months ended September 30, 2013 include revenues of $4.9 million from MPC.

Net Income

Net income for the nine months ended September 30, 2014 was $47.9 million, compared to $33.7 million for the nine months ended September 30, 2013, which represents an increase of $14.2 million. The increase in net income was principally attributable to the increase in income from continuing operations, as discussed above.

Liquidity and Capital Resources

Our principal sources of liquidity have been derived from cash flows from operations, proceeds from third party debt in the form of borrowings under credit facilities and private offerings, issuances of notes, project financing, tax monetization, short term borrowing under our lines of credit, and cash grants we received under the ARRA. We have utilized this cash to develop and construct power generation plants, fund our acquisitions, and meet our other cash and liquidity needs.

As of September 30, 2014, we had access to: (i) $42.5 million in cash and cash equivalents, of which $33.8 million is related to foreign jurisdictions and (ii) $229.1 million of unused corporate borrowing capacity under existing revolving lines of credit and lines for guarantees with different commercial banks.

Our estimated capital needs for the remainder of 2014 include approximately $55.0 million for capital expenditures required for new projects under development or construction, exploration activity, operating projects, and machinery and equipment purchases, as well as an additional $31.0 million for debt repayment.

We believe that based on our plans to increase our operations outside of the U.S., the cash generated from our operations outside of the U.S. will be reinvested outside of the U.S. In addition, our U.S. sources of cash and liquidity are sufficient to meet our needs in the U.S. and, accordingly, we do not currently plan to repatriate the funds we have designated as being permanently invested outside the U.S. If we change our plans, we may be required to accrue and pay U.S. taxes to repatriate these funds.

We expect to finance these requirements with: (i) the sources of liquidity described above; (ii) positive cash flows from our operations; and (iii) future project financing and refinancing (including construction loans). Management believes that these sources will address our anticipated liquidity, capital expenditures, and other investment requirements.

Third-Party Debt

Our third-party debt is composed of two principal categories. The first category consists of project finance debt or acquisition financing that we or our subsidiaries have incurred for the purpose of developing and constructing, refinancing or acquiring our various projects, which are described below under “Non-Recourse and Limited-Recourse Third-Party Debt”. The second category consists of debt incurred by us or our subsidiaries for general corporate purposes, which are described below under “Full-Recourse Third-Party Debt.”

Non-Recourse and Limited-Recourse Third-Party Debt

OFC Senior Secured Notes — Non-Recourse

In February 2004, OFC, one of our subsidiaries, issued $190.0 million of OFC Senior Secured Notes for the purpose of refinancing the acquisition cost of the Brady, Ormesa and Steamboat 1, 1A, 2 and 3 power plants, and the financing of the acquisition cost of 50% of the Mammoth complex. The OFC Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OFC Senior Secured Notes are payable in semi-annual payments. The OFC Senior Secured Notes are collateralized by substantially all of the assets of OFC and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC. There are various restrictive covenants under the OFC Senior Secured Notes, which include limitations on additional indebtedness of OFC and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC. In addition, there are restrictions on the ability of OFC to make distributions to its shareholders, which include a required historical and projected 12-month debt service coverage ratio (DSCR) of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OFC fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. We are only required to measure these covenants on a semi-annual basis and as of June 30, 2014, the last measurement date of the covenants, The actual historical 12-month DSCR was 1.33 and the pro-forma 12-month DSCR was 1.26 (on a semi-annual basis and as of June 30, 2014). There were $72.5 million and $90.8 million of OFC Senior Secured Notes outstanding as of September 30, 2014 and December 31, 2013, respectively.

In January 2014, we acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $13.2 million. We recognized a gain of approximately $0.3 million in the nine months ended September 30, 2014. In February 2013, we acquired from OFC noteholders OFC Senior Secured Notes with an outstanding aggregate principal amount of $12.8 million and we recognized a gain of $0.8 million in the year ended December 31, 2013.

OrCal Geothermal Senior Secured Notes — Non-Recourse

In December 2005, OrCal, one of our subsidiaries, issued $165.0 million of OrCal Senior Secured Notes for the purpose of refinancing the acquisition cost of the Heber complex. The OrCal Senior Secured Notes have been rated BBB- by Fitch Ratings. The OrCal Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OrCal Senior Secured Notes are payable in semi-annual payments. The OrCal Senior Secured Notes are collateralized by substantially all of the assets of OrCal and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OrCal. There are various restrictive covenants under the OrCal Senior Secured Notes which include limitations on additional indebtedness of OrCal and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OrCal. In addition, there are restrictions on the ability of OrCal to make distributions to its shareholders, which include a required historical and projected 12-month DSCR of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OrCal fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. We are only required to measure these covenants on a semi-annual basis and as of June 30, 2014, the last measurement date of the covenants, the actual historical 12-month DSCR was 1.26. There were $63.2 million and $66.2 million of OrCal Senior Secured Notes outstanding as of September 30, 2014 and December 31, 2013, respectively.

OFC 2 Senior Secured Notes — Limited Recourse during Construction and Non-Recourse Thereafter

In September 2011, OFC 2, one of our subsidiaries, and its wholly owned project subsidiaries (collectively, the OFC 2 Issuers) entered into a note purchase agreement (the Note Purchase Agreement) with OFC 2 Noteholder Trust, as purchaser, John Hancock, as administrative agent, and the DOE, as guarantor, in connection with the offer and sale of up to $350.0 million aggregate principal amount of OFC 2 Senior Secured Notes due December 31, 2034. As of September 30, 2014 we have utilized $291.7 million and we do not expect further draws under this agreement.

Subject to the fulfillment of customary and other specified conditions precedent, the OFC 2 Senior Secured Notes may be issued in up to six distinct series associated with the phased construction (Phase I and Phase II) of the Jersey Valley, McGinness Hills and Tuscarora geothermal power plants, which are owned by the OFC 2 Issuers. The OFC 2 Senior Secured Notes will mature and the principal amount of the OFC 2 Senior Secured Notes will be payable in equal quarterly installments and in any event not later than December 31, 2034. Each series of notes will bear interest at a rate calculated based on a spread over the U.S. Treasury yield curve that will be set at least ten business days prior to the issuance of such series of notes. Interest will be payable quarterly in arrears. The DOE guarantees payment of 80% of principal and interest on the OFC 2 Senior Secured Notes pursuant to Section 1705 of Title XVII of the Energy Policy Act of 2005, as amended. The conditions precedent to the issuance of the OFC 2 Senior Secured Notes include certain specified conditions required by the DOE in connection with its guarantee of the OFC 2 Senior Secured Notes.

In October 2011, the OFC 2 Issuers completed the sale of $151.7 million in aggregate principal amount of 4.687% Series A Notes due 2032 (the Series A Notes). The net proceeds from the sale of the Series A Notes, after deducting transaction fees and expenses, were approximately $147.4 million, and were used to finance a portion of the construction costs of Phase I of the McGinness Hills and Tuscarora power plants and to fund certain reserves. Principal and interest on the Series A Notes are payable quarterly in arrears on the last day of March, June, September and December of each year.

On June 20, 2014, Phase I of the Tuscarora facility achieved project completion under the OFC 2 Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement, we recalibrated the original financing assumptions and as a result the loan amount was adjusted through a principal prepayment of $4.3 million.

On August 29, 2014, OFC 2 signed a $140.0 million loan under the OFC 2 senior secured notes to finance the construction of the McGinness Hills Phase project. This drawdown is the last tranche (Series C notes) under the Note Purchase Agreement with John Hancock Life Insurance Company (USA) and guaranteed by the U.S. Department of Energy's Loan Programs Office in accordance with and subject to the Department's Loan Guarantee Program under Section 1705 of Title XVII of the Energy Policy Act of 2005. The $140.0 million loan, which matures in December 2032, carries a 4.61% coupon with principal to be repaid on a quarterly basis. The OFC 2 Notes, which include loans for the Tuscarora, Jersey Valley and McGinness Hills complexes, are rated "BBB" by Standard & Poor's.

In connection with the anticipated drawdown, on August 13, 2014, we entered into an on-the-run interest rate lock agreement with a financial institution with a termination date of August 15, 2014. This on-the-run interest rate lock agreement had a notional amount of $140.0 million and was designated by us to be a cash flow hedge. The objective of this cash flow hedge was to eliminate the variability in the changes in the 10-year U.S. Treasury rate as that is one of the components in the annual interest rate of the OFC 2 loan that was forecasted to be fixed on August 15, 2014. As such, we hedged the variability in total proceeds attributable to changes in the 10-year U.S. Treasury rate for the forecasted issuance of fixed rate OFC 2 loan. On August 18, 2014, the settlement date, we paid $1.5 million to the counterparty of the on-the-run interest rate lock agreement.

The OFC 2 Senior Secured Notes are collateralized by substantially all of the assets of OFC 2 and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC 2. There are various restrictive covenants under the OFC 2 Senior Secured Notes, which include limitations on additional indebtedness of OFC 2 and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC 2. In addition, there are restrictions on the ability of OFC 2 to make distributions to its shareholders. Among other things, the distribution restrictions include a historical and projected quarterly DSCR requirement of at least 1.2 (on a blended basis for all of the OFC 2 power plants) and 1.5 on a pro forma basis (giving effect to the distributions). We are required to measure these covenants on a quarterly basis and as of September 30, 2014, the last measurement date of the covenants, the actual DSCR was 2.67 and the pro-forma 12-month DSCR was 2.20. There were $274.5 million and $144.4 million of OFC 2 Senior Secured Notes outstanding as of September 30, 2014 and December 31, 2013, respectively.

We provided a guarantee in connection with the issuance of the C Notes. One trigger event is the failure of any facility financed by the relevant series of OFC 2 Senior Secured Notes to reach completion and meet certain operational performance levels (the non-performance trigger) which gives rise to a prepayment obligation on the OFC 2 Senior Secured Notes. The other trigger event is a payment default on the OFC 2 Senior Secured Notes or the occurrence of certain fundamental defaults that result in the acceleration of the OFC 2 Senior Secured Notes, in each case that occurs prior to the date that the relevant facility financed by such OFC 2 Senior Secured Notes reaches completion and meets certain operational performance levels. A demand on our guarantee based on the non-performance trigger is limited to an amount equal to the prepayment amount on the OFC 2 Senior Secured Notes necessary to bring the OFC 2 Issuers into compliance with certain coverage ratios. A demand on our guarantee based on the other trigger event is not so limited.

Olkaria III Finance Agreement with OPIC — Limited Recourse during Construction and Non-Recourse Thereafter

In August 2012, OrPower 4, one of our subsidiaries, entered into a finance agreement with OPIC, an agency of the United States government, to provide limited-recourse senior secured debt financing in an aggregate principal amount of up to $310.0 million (the OPIC Loan) for the refinancing and financing of our Olkaria III geothermal power complex in Kenya. The finance agreement was amended on November 9, 2012.

The OPIC Loan is comprised of three tranches:

- Tranche I in an aggregate principal amount of $85.0 million, which was drawn in November 2012, was used to prepay approximately $20.5 million (plus associated prepayment penalty and breakage costs of $1.5 million) of the DEG Loan, as described below under “Full Recourse Debt”. The remainder of Tranche I proceeds was used for reimbursement of prior capital costs and other corporate purposes.

- Tranche II in an aggregate principal amount of $180.0 million was used to fund the construction and well field drilling for Plant 2 of the Olkaria III geothermal power complex. In November 2012, an amount of $135.0 million was disbursed under this Tranche II, and in February 2013 the remaining $45.0 million was distributed under this Tranche II.

- Tranche III in an aggregate principal amount of $45.0 million was used to fund the construction of Plant 3 of the Olkaria III geothermal power complex and was drawn down in full in November 2013.

In July 2013, we completed the conversion of the interest rate applicable to both Tranche I and Tranche II from a floating interest rate to a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance of $76.7 million and matures on December 15, 2030, and Tranche II, which has an outstanding balance of $166.80 million and matures on June 15, 2030, is 6.31%. In November 2013, we fixed the interest rate applicable to Tranche III. The fixed interest rate for Tranche III, which has an outstanding balance of $43.7 million and matures on December 15, 2030, is 6.12%.

OrPower 4 has a right to make voluntary prepayments of all or a portion of the OPIC Loan subject to prior notice, minimum prepayment amounts, and a prepayment premium of 2.0% in the first two years after the Plant 2 commercial operation date, declining to 1% in the third year after the Plant 2 commercial operation date, and without premium thereafter, plus a redemption premium. In addition, the OPIC Loan is subject to customary mandatory prepayment in the event of certain reductions in generation capacity of the power plants, unless such reductions will not cause the projected ratio of cash flow to debt service to fall below 1.7.

The OPIC Loan is secured by substantially all of OrPower 4's assets and by a pledge of all of the equity interests in OrPower 4.

The finance agreement includes customary events of default, including failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations and warranties, non-payment or acceleration of other debt of OrPower 4, bankruptcy of OrPower 4 or certain of its affiliates, judgments rendered against OrPower 4, expropriation, change of control, and revocation or early termination of security documents or certain project-related agreements, subject to various exceptions and notice, cure and grace periods.

The repayment of the remaining outstanding DEG Loan (see “Full-Recourse Third-Party Debt” below) in the amount of approximately $35.5 million as of September 30, 2014, has been subordinated to the OPIC Loan.

There are various restrictive covenants under the OPIC Loan, which include a required historical and projected 12-month DSCR of not less than 1.4 (measured as of March 15, June 15, September 15 and December 15 of each year). If OrPower 4 fails to comply with these financial ratios it will be prohibited from making distributions to its shareholders. In addition, if the DSCR falls below 1.1, subject to certain cure rights such failure will constitute an event of default by OrPower 4. This covenant in respect of Tranche I will become effective on December 15, 2014.

There were $287.1 million and $299.9 million of the OPIC Loan outstanding as of September 30, 2014 and December 31, 2013, respectively.

Amatitlan Loan — Non-Recourse

In May 2009, Ortitlan, one of our subsidiaries, entered into a note purchase agreement in an aggregate principal amount of $42.0 million which refinanced its investment in the 20 MW geothermal power plant located in Amatitlan, Guatemala. The loan was provided by EIG Global Project Fund II, Ltd. (formerly TCW). On September 30, 2014, we repaid the loan in full. The outstanding amount at the time of repayment was approximately $30.0 million.

Full-Recourse Third-Party Debt

Union Bank. In February 2012, Ormat Nevada entered into an amended and restated credit agreement with Union Bank. The credit termination date was extended from February 15, 2012 to February 7, 2014, which was subsequently extended to May 20, 2015. The aggregate amount available under the credit agreement is $50.0 million. The facility is limited to the issuance, extension, modification or amendment of letters of credit. Union Bank is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as parties thereto. In connection with this transaction, we entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which we agreed to guarantee Ormat Nevada’s obligations under the credit agreement. Ormat Nevada’s obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of September 30, 2014: (i) the actual 12-month debt to EBITDA ratio was 3.31; (ii) the 12-month DSCR was 2.56; and (iii) the distribution leverage ratio was 0.72. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of Union Bank.

As of September 30, 2014, letters of credit in the aggregate amount of $42.7 million remain issued and outstanding under this credit agreement.

HSBC. In May 2013, Ormat Nevada, our wholly owned subsidiary, entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals, which was extended to May 31, 2015, pursuant to Amendment No. 1 to the credit agreement. The aggregate amount available under the credit agreement is $25.0 million. This credit line is limited to the issuance, extension, modification or amendment of letters of credit and $10.0 million out of this credit line is available to be drawn for working capital needs. HSBC is currently the sole lender and issuing bank under the credit agreement, but is also designated as an administrative agent on behalf of banks that may, from time to time in the future, join the credit agreement as parties thereto. In connection with this transaction, we entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which we agreed to guarantee Ormat Nevada’s obligations under the credit agreement. Ormat Nevada’s obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of September 30, 2014: (i) the actual 12-month debt to EBITDA ratio was 3.31; (ii) the 12-month DSCR was 2.56; and (iii) the distribution leverage ratio was 0.72. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios, and subject to specified carve-outs and exceptions, a negative pledge on the assets of Ormat Nevada in favor of HSBC.

As of September 30, 2014, letters of credit in the aggregate amount of $21.3 million remain issued and outstanding under this committed credit agreement.

Credit Agreements. We also have committed credit agreements with five other commercial banks for an aggregate amount of $550.8 million. Under the terms of these credit agreements, we or our Israeli subsidiary, Ormat Systems, can request (i) extensions of credit in the form of loans and/or the issuance of one or more letters of credit in the amount of up to $287.0 million and (ii) the issuance of one or more letters of credit in the amount of up to $263.8 million. The credit agreements mature end of December 2014 and November 2016. Loans and draws under the credit agreements or under any letters of credit will bear interest at the respective bank's cost of funds plus a margin.

As of September 30, 2014, loans in the total amount of $28.1 million were outstanding, and letters of credit with an aggregate stated amount of $302.5 million were issued and outstanding under these credit agreements. The $28.1 million in loans are for terms of three months or less and bear interest at a weighted average rate of 2.33%.

Term Loans. We have a $20.0 million term loan with a group of institutional investors, which matures on July 16, 2015, is payable in 12 semi-annual installments commencing January 16, 2010, and bears interest at a rate of 6.50%. As of September 30, 2014, $3.9 million was outstanding under this loan.

We have a $20.0 million term loan with a group of institutional investors, which matures on August 1, 2017, is payable in 12 semi-annual installments commencing February 1, 2012, and bears interest at 6-month LIBOR plus 5.00%. As of September 30, 2014, $10.0 million was outstanding under this loan.

We have a $20.0 million term loan with a group of institutional investors, which matures on November 16, 2016, is payable in ten semi-annual installments commencing May 16, 2012, and bears interest at a rate of 5.75%. As of September 30, 2014, $10.0 million was outstanding under this loan.

We have a $50.0 million term loan with a commercial bank, which matures on November 10, 2014, is payable in ten semi-annual installments commencing May 10, 2010, and bears interest at 6-month LIBOR plus 3.25%. As of September 30, 2014, $5.0 million was outstanding under this loan.

Senior Unsecured Bonds. We have an aggregate principal amount of approximately $250.0 million of Senior Unsecured Bonds issued and outstanding. We issued approximately $142.0 million of these bonds in August 2010 and an additional $107.5 million in February 2011. Subject to early redemption, the principal of the bonds is repayable in a single bullet payment upon the final maturity of the bonds on August 1, 2017. The bonds bear interest at a fixed rate of 7.00%, payable semi-annually. The bonds that we issued in February 2011 were issued at a premium which reflects an effective fixed interest of 6.75%.

Loan Agreement with DEG (The Olkaria III Complex). OrPower 4 entered into a project financing loan to refinance its investment in Plant 1 of the Olkaria III complex located in Kenya with a group of European Development Finance Institutions arranged by Deutsche Investitions-und Entwicklungsgesellschaft mbH (DEG). The DEG Loan will mature on December 15, 2018, and is payable in 19 equal semi-annual installments. Interest on the loan is variable based on 6-month LIBOR plus 4.0%. We fixed the interest rate on most of the loan at 6.90%. Currently, $35.5 million is outstanding under the DEG Loan (out of which $24.4 million bears interest at a fixed rate).

In October 2012, OrPower 4, DEG and the other parties thereto amended and restated the DEG Loan Agreement. The amendment became effective on November 9, 2012 upon the execution by OrPower 4 of the Tranche I and Tranche II Notes under the OPIC loan and the related disbursements of the proceeds thereof under the OPIC Finance Agreement (as described above under the heading “Non-Recourse and Limited –Recourse Third-Party Debt”). As part of the amendment we prepaid in full two loans under the DEG facility in the total principal amount of approximately $20.5 million. The amended and restated DEG Loan Agreement provides for: (i) the release and discharge of all collateral security previously provided by OrPower 4 to the secured parties under the DEG Loan Agreement and the substitution of our guarantee of OrPower 4’s payment and certain other performance obligations in lieu thereof; (ii) the establishment of a LIBOR floor of 1.25% in respect of one of the loans under the DEG Loan Agreement; and (iii) the elimination of most of the affirmative and negative covenants under the DEG Loan Agreement and certain other conforming provisions as a result of OrPower 4’s execution of the OPIC Finance Agreement and its obligations thereunder.

Our obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds, described above, are unsecured, but we are subject to a negative pledge in favor of the banks and the other lenders and certain other restrictive covenants. These include, among other things, a prohibition on: (i) creating any floating charge or any permanent pledge, charge or lien over our assets without obtaining the prior written approval of the lender; (ii) guaranteeing the liabilities of any third party without obtaining the prior written approval of the lender; and (iii) selling, assigning, transferring, conveying or disposing of all or substantially all of our assets, or a change of control in our ownership structure. Some of the credit agreements, the term loan agreements, and the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, we have agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600.0 million and in no event less than 30% of total assets; (ii) 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio not to exceed 7.0; and (iii) dividend distributions not to exceed 35% of net income in any calendar year. As of September 30, 2014 (i) total equity was $783.5 million and the actual equity to total assets ratio was 36.1%; and (ii) the 12-month debt, net of cash and cash equivalents, to Adjusted EBITDA ratio was 3.98. The failure to perform or observe any of the covenants set forth in such agreements, subject to various cure periods, would result in the occurrence of an event of default and would enable the lenders to accelerate all amounts due under each such agreement.

As described above, we are currently in compliance with our covenants with respect to the credit agreements, the loan agreements and the trust instrument, and believe that the restrictive covenants, financial ratios and other terms of any of our (or Ormat Systems') full-recourse bank credit agreements will not materially impact our business plan or operations.

Letters of Credit

Some of our customers require our project subsidiaries to post letters of credit in order to guarantee their respective performance under relevant contracts. We are also required to post letters of credit to secure our obligations under various leases and licenses and may, from time to time, decide to post letters of credit in lieu of cash deposits in reserve accounts under certain financing arrangements. In addition, our subsidiary, Ormat Systems, is required from time to time to post performance letters of credit in favor of our customers with respect to orders of products.

As of September 30, 2014, committed letters of credit in the aggregate amount of $362.0 million remained issued and outstanding, of which $360.6 million were issued under the credit agreements with Union Bank, HSBC and five of the commercial banks as described under "Full-Recourse Third Party Debt". In addition, $1.4 million were issued under non-committed lines of credit.

Puna Power Plant Lease Transactions

In May 2005, Puna Geothermal Venture (PGV), our Hawaiian subsidiary, entered into a transaction involving the original geothermal power plant of the Puna complex located on the Big Island. The transaction was concluded with financing parties by means of a leveraged lease transaction. A secondary stage of the lease transaction relating to two new geothermal wells that PGV drilled in the second half of 2005 (for production and injection) was completed on December 30, 2005. Pursuant to a 31-year head lease, PGV leased its geothermal power plant to the abovementioned financing parties in return for payments of $83.0 million by such financing parties to PGV, which are accounted for as deferred lease income.

OPC Transaction

In June 2007, Ormat Nevada entered into agreements with affiliates of Morgan Stanley & Co. Incorporated and Lehman Brothers Inc. (Morgan Stanley Geothermal LLC and Lehman OPC LLC, respectively), under which those investors purchased, for cash, interests in a newly formed subsidiary of Ormat Nevada, OPC, entitling the investors to certain tax benefits (such as PTCs and accelerated depreciation) and distributable cash associated with four geothermal power plants in Nevada.

The first closing under the agreements occurred in 2007 and covered our Desert Peak 2, Steamboat Hills, and Galena 2 power plants. The investors paid $71.8 million at the first closing. The second closing under the agreements occurred in 2008 and covered the Galena 3 power plant. The investors paid $63.0 million at the second closing.

Ormat Nevada continues to operate and maintain the power plants. Under the agreements, Ormat Nevada initially received all of the distributable cash flow generated by the power plants, while the investors received substantially all of the PTCs and the taxable income or loss (together, the Economic Benefits). Once Ormat Nevada recovered the capital that it invested in the power plants, which occurred in the fourth quarter of 2010, the investors began receiving both the distributable cash flow and the Economic Benefits. Once the investors reach a target after tax yield on their investment in OPC (the OPC Flip Date), Ormat Nevada will receive 95% of both distributable cash and taxable income, on a going forward basis. Following the OPC Flip Date, Ormat Nevada also has the option to purchase the investors' remaining interest in OPC at the then-current fair market value or, if greater, the investors' capital account balances in OPC. If Ormat Nevada were to exercise this purchase option, it would become the sole owner of the power plants again.

Our voting rights in OPC are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, we own all of the Class A membership units, which represent 75% of the voting rights in OPC, and the investors (as described below) own all of the Class B membership units, which represent 25% of the voting rights of OPC. Other than in respect of customary protective rights, all operational decisions in OPC are decided by the vote of a majority of the membership units. Following the OPC Flip Date, Ormat Nevada's voting rights will increase to 95% and the investor's voting rights will decrease to 5%. Ormat Nevada retains the controlling voting interest in OPC both before and after the OPC Flip Date and therefore consolidates OPC.

The Class B membership units are provided with a 5% residual economic interest in OPC, which commences as of the OPC Flip Date. This residual 5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments. The Class B membership units are currently held by Morgan Stanley Geothermal LLC and JPM. On October 30, 2009, Ormat Nevada acquired from Lehman OPC LLC all of the Class B membership units of OPC held by Lehman OPC LLC pursuant to a right of first offer for a purchase price of $18.5 million in cash and on February 3, 2011, Ormat Nevada sold to JPM all of the Class B membership units of OPC that it had acquired for a sale price of $24.9 million in cash.

ORTP Transaction

On January 24, 2013, Ormat Nevada entered into agreements with JPM under which JPM purchased interests in a newly formed subsidiary of Ormat Nevada, ORTP, entitling JPM to certain tax benefits (such as PTCs and accelerated depreciation) associated with certain geothermal power plants in California and Nevada.

Under the terms of the transaction, Ormat Nevada transferred the Heber complex, the Mammoth complex, the Ormesa complex, and the Steamboat 2 and 3, Burdette (Galena 1) and Brady power plants to ORTP, and sold class B membership units in ORTP to JPM. In connection with the closing, JPM paid approximately $35.7 million to Ormat Nevada and will make additional payments to Ormat Nevada of 25% of the value of PTCs generated by the portfolio over time. The additional payments are expected to be made until December 31, 2016 and total up to a maximum amount of $11.0 million, of which we received $2.2 million in the first quarter of 2014.

Ormat Nevada will continue to operate and maintain the power plants. Under the agreements, Ormat Nevada will initially receive all of the distributable cash flow generated by the power plants, while JPM will receive substantially all of PTCs and the taxable income or loss (together, the Economic Benefits). JPM’s return is limited by the terms of the transaction. Once JPM reaches a target after tax yield on its investment in ORTP (the ORTP Flip Date), Ormat Nevada will receive 97.5% of the distributable cash and 95.0% of the taxable income, on a going forward basis. At any time during the twelve-month period after the end of the fiscal year in which the ORTP Flip Date occurs (but no earlier than the expiration of five years following the date that the last of the power plants was placed in service for purposes of federal income taxes), Ormat Nevada also has the option to purchase JPM’s remaining interest in ORTP at the then-current fair market value. If Ormat Nevada were to exercise this purchase option, it would become the sole owner of the power plants again.

The Class B membership units entitle the holder to a 5.0% (allocation of income and loss) and 2.5% (allocation of cash) residual economic interest in ORTP. The 5.0% and 2.5% residual interest commences on achievement by JPM of a contractually stipulated return that triggers the ORTP Flip Date. The actual ORTP Flip Date is not known with certainty. This residual 5.0% and 2.5% interest represents a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments.

Our voting rights in ORTP are based on a capital structure that is comprised of Class A and Class B membership units. Through Ormat Nevada, we own all of the Class A membership units, which represent 75.0% of the voting rights in ORTP. JPM owns all of the Class B membership units, which represent 25.0% of the voting rights of ORTP. Other than in respect of customary protective rights, all operational decisions in ORTP are decided by the vote of a majority of the membership units. Ormat Nevada retains the controlling voting interest in ORTP both before and after the ORTP Flip Date and therefore will continue to consolidate ORTP.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 11 to our condensed consolidated financial statements set forth in Item 1 of this quarterly report, we have a liability associated with unrecognized tax benefits and related interest and penalties in the amount of approximately $5.6 million as of September 30, 2014. This liability is included in long-term liabilities in our condensed consolidated balance sheet, because we generally do not anticipate that settlement of the liability will require payment of cash within the next twelve months. We are not able to reasonably estimate when we will make any cash payments required to settle this liability.

Dividends

The following are the dividends declared by us since September 30, 2012:

Date Declared	Dividend Amount per Share	Record Date	Payment Date
August 8, 2013	$0.04	August 19, 2013	August 29, 2013
November 6, 2013	$0.04	November 20, 2013	December 4, 2013
February 25, 2014	$0.06	March 13, 2014	March 27, 2014
May 8, 2014	$0.05	May 21, 2014	May 30, 2014
August 5, 2014	$0.05	August 19, 2014	August 28, 2014

Historical Cash Flows

The following table sets forth the components of our cash flows for the relevant periods indicated:

	Nine Months Ended September 30,	
	2014	**2013**
	(In thousands)	
Net cash provided by operating activities	$178,770	$32,226
Net cash used in investing activities	(135,435)	(128,198)
Net cash provided by (used in) financing activities	(58,238)	64,779
Net change in cash and cash equivalents	(14,903)	(31,193)

For the Nine Months Ended September 30, 2014

Net cash provided by operating activities for the nine months ended September 30, 2014 was $178.8 million, compared to $32.2 million for the nine months ended September 30, 2013. The net increase of $146.6 million resulted primarily from: (i) a decrease in receivables of $21.6 million in the nine months ended September 30, 2014, compared to an increase of $23.2 million in the nine months ended September 30, 2013, as a result of timing of collection from our customers; (ii) an increase in billings in excess of costs and estimated earnings on uncompleted contracts, net of

$43.8 million in our Product Segment in the nine months ended September 30, 2014, compared to a decrease of $39.3 million in the nine months ended September 30, 2013; and (iii) the increase in cash inflow from higher net income of $14.2 million, from a net income of $33.7 million for the nine months ended September 30, 2013 to $47.9 million for the nine months ended September 30, 2014 as described above.

Net cash used in investing activities for the nine months ended September 30, 2014 was $135.4 million, compared to $128.2 million for the nine months ended September 30, 2013. The principal factors that affected our net cash used in investing activities during the nine months ended September 30, 2014 were (i) capital expenditures of $122.6 million, primarily for our facilities under construction; and (ii) a net increase of $76.4million in restricted cash and cash equivalents, due to timing of debt repayments, reduced by (i) cash grant of $27.4 million received from the U.S. Treasury under Section 1603 of the ARRA relating to our Don A. Campbell power plant and our G1 refurbishment power plant at the Mammoth Complex, and (ii) $35.3 million cash received due to the sale of Heber Solar The principal factors that affected our net cash used in investing activities during the nine months ended September 30, 2013 were (i) capital expenditures of $144.6 million, primarily for our facilities under construction, and (ii) a net increase of $7.7 million in restricted cash, cash equivalents and marketable securities, reduced by: (i) cash grant of $14.7 million received from the U.S. Treasury under Section 1603 of the ARRA in the third quarter of 2013 relating to our Brawley geothermal power plant; and (ii) $7.7 million cash received from the sale of our subsidiary.

Net cash used in financing activities for the nine months ended September 30, 2014 was $58.2 million, compared to $64.8 million provided by financing activities for the nine months ended September 30, 2013. The principal factors that affected the net cash used in financing activities during the nine months ended September 30, 2014 were: (i) net repayment of $83.9 million under our revolving credit lines with commercial banks (ii) the repayment of long-term debt in the amount of $80.2 million; (iii) $12.9 million of cash paid to repurchase our OFC Senior Secured Notes; (iv) $7.3 million cash dividend paid; and (v) $9.2 million of cash paid to noncontrolling interest The principal factors that affected our net cash provided by financing activities during the nine months ended September 30, 2013 were: (i) $45.0 million of net proceeds from the disbursement from Tranche II of the OPIC Loan, as described above under “Non-Recourse and Limited-Recourse Third-Party Debt”; (ii) $31.4 million of net proceeds from the ORTP Transaction (see “ORTP Transaction” above); and (iii) a net increase of $49.7 million against our revolving lines of credit with commercial banks. This increase was partially offset due to: (i) $11.9 million of cash paid to repurchase our OFC Senior Secured Notes; (ii) the repayment of long-term debt in the amount of $37.5 million; and (iii) $10.2 million of cash paid to the Class B membership units of OPC (see “OPC Transaction” above).

EBITDA and Adjusted EBITDA

We calculate EBITDA as net income before interest, taxes, depreciation and amortization. We calculate Adjusted EBITDA as net income before interest, taxes, depreciation and amortization, excluding impairment of long-lived assets and a one-time termination fee. EBITDA and Adjusted EBITDA are not measurements of financial performance or liquidity under GAAP and should not be considered as alternatives to cash flow from operating activities or as measures of liquidity or alternatives to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with GAAP. EBITDA and Adjusted EBITDA are presented because we believe they are frequently used by securities analysts, investors and other interested parties in the evaluation of a company’s ability to service and/or incur debt. However, other companies in our industry may calculate EBITDA and Adjusted EBITDA differently than we do. This information should not be considered in isolation or as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP or other non-GAAP financial measures.

Adjusted EBITDA for the three months ended September 30, 2014 was $69.2 million, compared to $60.3 million for the three months ended September 30, 2013. Adjusted EBITDA for the nine months ended September 30, 2014 was $199.6 million, compared to $175.7 million for the nine months ended September 30, 2013.

The following table reconciles net cash provided by operating activities to EBITDA and Adjusted EBITDA for the three and nine-month periods ended September 30, 2014 and 2013:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2014	**2013**	**2014**	**2013**
	(In thousands)		**(In thousands)**	
Net cash provided by operating activities	$75,191	$12,276	$178,770	$32,226
Adjusted for:				
Interest expense, net (excluding amortization of deferred financing costs)	20,038	17,405	59,366	47,367
Interest income	(35)	(742)	(236)	(870)
Income tax provision	6,444	5,201	17,731	15,642
Adjustments to reconcile net income or loss to net cash provided by operating activities (excluding depreciation and amortization)	(32,404)	26,115	(56,062)	72,361
EBITDA	$69,234	$60,255	$199,569	$166,726
Termination fee	—	—	—	8,979
Adjusted EBITDA	$69,234	$60,255	$199,569	$175,705
Net cash used in investing activities	$(106,423)	$(25,029)	$(135,435)	$(128,198)
Net cash provided by (used in) financing activities	$(6,437)	$19,295	$(58,238)	$64,779

Capital Expenditures

Our capital expenditures primarily relate to two principal components: (i) the enhancement of our existing power plants and (ii) the development and construction of new power plants.

The following is an overview of projects that are fully released for construction:

McGinness Hills Phase 2. We are currently developing McGinness Hills phase 2 project located in Lander County, Nevada and are expecting to bring the complex's total capacity to approximately 70MW. Field development is in process and most of the equipment is on its way to the site. We signed an amendment to the McGinness 20-year PPA with NV Energy to include phase 2. The new power plant is expected to come online in the first quarter of 2015.

Mammoth Complex. We are currently in the process of evaluating the refurbishment program for the Mammoth complex located in Mammoth Lakes, California. The refurbishment program includes replacement of the old units with new equipment manufactured by us. We expect the replacement of the equipment to optimize the operation of the complex. We expect to complete the refurbishment in 2015.

Sarulla project. We are a member of a consortium which is in the process of developing the Sarulla geothermal power project in Indonesia, with expected generating capacity of approximately 330 MW. We own 12.75% of the project directly through our 100% owned special purpose entity. We also own 12.75% of an Indonesian special purpose entity that will develop and operate the project.

Following the financial close of the financing for the project in May 2014, the project was released for construction. Field development and initial site construction have started. The project is being constructed in three phases of 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant's efficiency. The OEC units that we are supplying to the project under a supply contract from the EPC contractor are in early stages of production.

The following is an overview of projects that are in an initial stage of construction:

Carson Lake Project. We plan to develop the 20 MW Carson Lake project on Bureau of Land Management (BLM) leases located in Churchill County, Nevada. Permitting delays prevented substantial progress on the project site until late last year and have had a significant impact on the development plan and the economics of the project. As a result, in December 2011, we terminated the project's PPA and the joint operating agreement with Nevada Power Company. We are not planning to invest material capital expenditures in this project in 2014.

CD 4 Project. We plan to develop 30 MW of new capacity at the Mammoth complex, on land which is comprised mainly of BLM leases. We have commenced field development and drilled one production well and one injection well. Continued drilling is subject to receipt of additional permits. As part of the process to secure a transmission line, we are participating in the SCE Wholesale Distribution Access Tariff Transition Cluster Generator Interconnection Process to deliver energy into the Southern California Edison system at the Casa Diablo Substation. We are not planning to invest material capital expenditures in this project in 2014.

We have estimated approximately $184.0 million in capital expenditures for the projects listed above, and for enhancement of our existing power plants, of which we have invested approximately $89.0 million as of September 30, 2014. We expect to invest $23.0 million of such total during the remainder of 2014 and the remaining $72.0 million thereafter.

In addition, we estimate approximately $32.0 million in additional capital expenditures in the remainder of 2014 to be allocated as follows: (i) $15.0 million in development of new projects; (ii) $7.0 million for maintenance capital expenditure of our operating power plants (iii) $8.0 million in exploration activities in various leases for geothermal resources in which we have started the exploration activity and (iv) $2.0 million in enhancement of our production facilities. In the aggregate, we estimate our total capital expenditures for the remainder of 2014 will be approximately

$55.0 million.

Exposure to Market Risks

Based on current conditions, we believe that we have sufficient financial resources to fund our activities and execute our business plans. However, the cost of obtaining financing for our project needs may increase significantly or such financing may be difficult to obtain.

One market risk to which power plants are typically exposed is the volatility of electricity prices. Our exposure to such market risk is currently limited because many of our long-term PPAs (except for the 25 MW PPA for the Puna complex and the PPAs of the Heber 1 and 2 power plants in the Heber complex, the Ormesa complex and the G2 power plant in the Mammoth complex) have fixed or escalating rate provisions that limit our exposure to changes in electricity prices. Beginning in May 2012, the energy payments under the PPAs of the Heber 1 and 2 power plants in the Heber complex, the Ormesa complex and the G2 power plant in Mammoth complex are determined by reference to the relevant power purchaser's SRAC. A decline in the price of natural gas will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from natural gas, which in turn will reduce the variable energy rate that we may charge under the relevant PPA for these power plants. In addition, in October 2013 and March 2014, we entered into derivative transactions to reduce our exposure to the price of natural gas, under these PPAs, until March 31, 2015. The Puna complex is currently benefiting from energy prices which are higher than the floor under the 25 MW PPA for the Puna complex as a result of the high fuel costs that impact Hawaii Electric Light Company's (HELCO) avoided costs. Likewise, in October 2013, we entered into derivative transaction to reduce our exposure to the price of oil, under the 25 MW PPA of the Puna complex, until December 31, 2014.

As of September 30, 2014, 94.8% of our consolidated long-term debt comprised a fixed rate debt and therefore was not subject to interest rate volatility risk. As of such date, 5.2% of our long-term debt was in the form of a floating rate instrument, exposing us to changes in interest rates in connection therewith. As of September 30, 2014, $54.3 million of our long-term debt remained subject to some floating rate risk.

We currently maintain our surplus cash in short-term, interest-bearing bank deposits, money market securities and commercial paper (with a minimum investment grade rating of AA by Standard & Poor’s Ratings Services.)

Our cash equivalents are subject to market risk due to changes in interest rates. Fixed rate securities may have their market value adversely impacted due to a rise in interest rates, while floating rate securities may produce less income than expected if interest rates fall. Due in part to these factors, our future investment income may fall short of expectation due to changes in interest rates or we may suffer losses in principal if we are forced to sell securities that decline in market value due to changes in interest rates. However, because we classify our debt securities as “available-for-sale”, no gains or losses are recognized due to changes in interest rates unless such securities are sold prior to maturity or declines in fair value are determined to be other-than-temporary.

Another market risk to which we are exposed is potential adverse changes in foreign currency exchange rates, in particular the fluctuation of the U.S. dollar versus the NIS. Risks attributable to fluctuations in currency exchange rates can arise when we or any of our foreign subsidiaries borrow funds or incur operating or other expenses in one type of currency but receive revenues in another. In such cases, an adverse change in exchange rates can reduce such subsidiary’s ability to meet its debt service obligations, reduce the amount of cash and income we receive from such foreign subsidiary, or increase such subsidiary’s overall expenses. Risks attributable to fluctuations in foreign currency exchange rates can also arise when the currency denomination of a particular contract is not the U.S. dollar. Substantially all of our PPAs in the international markets are either U.S. dollar-denominated or linked to the U.S. dollar. Our construction contracts from time to time contemplate costs which are incurred in local currencies. The way we often mitigate such risk is to receive part of the proceeds from the sale contract in the currency in which the expenses are incurred. Currently, we have forward contracts in place to reduce our foreign currency exposure, and expect to continue to use currency exchange and other derivative instruments to the extent we deem such instruments to be the appropriate tool for managing such exposure. We do not believe that our exchange rate exposure has or will have a material adverse effect on our financial condition, results of operations or cash flows.

We performed a sensitivity analysis on the fair values of our swap contracts on oil and natural gas prices, long-term debt obligations, and foreign currency exchange forward contracts. The swap contracts on oil and natural gas prices and foreign currency exchange forward contracts listed below principally relate to trading activities. The sensitivity analysis involved increasing and decreasing forward rates at September 30, 2014 and December 31, 2013 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations as of September 30, 2014 and December 31, 2013 are presented below:

Risk	**Assuming a 10% Increase in Rates**	**Assuming a 10% Decrease in Rates**

	September 30, 2014	December 31, 2013	September 30, 2014	December 31, 2013	Change in the Fair Value of
	(Dollars in thousands)				
NGI Price	$ (2,033)	$ (3,552)	$ 2,033	$ 3,522	NGI Swap
NYMEX Heating Oil Price	(775)	(3,442)	775	3,442	NYMEX HO2 Swap
Foreign Currency	(7,121)	(3,381)	3,853	4,133	Foreign currency forward contracts
Interest Rate	(1,231)	(2,562)	1,264	2,690	OFC
Interest Rate	(1,027)	(1,298)	1,056	1,339	OrCal
Interest Rate	(10,541)	(5,519)	11,326	5,962	OFC 2
Interest Rate	(280)	(379)	286	388	Loan from DEG
Interest Rate	(10,734)	(11,836)	11,427	12,683	Loan from OPIC
Interest Rate	-	(328)	-	333	Loan from TCW
Interest Rate	(3,379)	(4,349)	3, 434	4,438	Senior unsecured bonds

Effect of Inflation

We do not expect that inflation will be a significant risk in the near term, given the current global economic conditions, however, that could change in the future. To address rising inflation, some of our contracts include certain mitigating factors against any inflation risk.

In connection with the Electricity Segment, inflation may directly impact an expense incurred for the operation of our projects, hence increasing the overall operating cost to us. The negative impact of inflation may be partially offset by price adjustments built into some of our PPAs that could be triggered upon such occurrences. The energy payments pursuant to the PPAs for the Brady power plant, the Steamboat 2 and 3 power plant, the Steamboat Hills power plant, and the Burdette power plant increase every year through the end of the relevant terms of such agreements, though such increases are not directly linked to the CPI or any other inflationary index. Lease payments are generally fixed, while royalty payments are generally determined as a percentage of revenues and therefore are not significantly impacted by inflation. In our Product Segment, inflation may directly impact fixed and variable costs incurred in the construction of our power plants, hence increasing our operating costs in that segment. In this segment, it is more likely that we will be able to offset part or all of the inflationary impact through our project pricing. With respect to power plants that we construct for our own electricity production, inflationary pricing may impact our operating costs which may be partially offset in the pricing of the new long-term PPAs that we negotiate.

Concentration of Credit Risk

Our credit risk is currently concentrated with the following major customers: Southern California Edison, HELCO, KPLC and Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy). If any of these electric utilities fails to make payments under its PPAs with us, such failure would have a material adverse impact on our financial condition.

Sierra Pacific Power Company and Nevada Power Company accounted for 14.6% and 15.3% of our total revenues for the three months ended September 30, 2014 and 2013, respectively, and 16.6% and 17.0% of our total revenues for the nine months ended September 30, 2014 and 2013, respectively.

Southern California Edison accounted for 19.8% and 20.9% of our total revenues for the three months ended September 30, 2014 and 2013, respectively, and 15.2% and 14.9% for the nine months ended September 30, 2014 and 2013, respectively. Southern California Edison is also the power purchaser and revenue source for our Mammoth project, which we accounted for separately under the equity method of accounting through August 1, 2010.

HELCO accounted for 7.3% and 8.7% of our total revenues for the three months ended September 30, 2014 and 2013, respectively, and 8.8% and 8.9% for the nine months ended September 30, 2014 and 2013, respectively.

KPLC accounted for 15.7% and 13.9% of our total revenues for the three months ended September 30, 2014 and 2013, respectively, and 15.6% and 10.9% for the nine months ended September 30, 2014 and 2013, respectively.

Government Grants and Tax Benefits

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. If we started construction of a new geothermal power plant in the U.S. by December 31, 2013, we are permitted to claim a tax credit against our U.S. federal income taxes equal to 30% of certain eligible costs when the project is placed in service. If we fail to meet the start of construction deadline for such a project, then the 30% credit is reduced to 10%. In lieu of the 30% tax credit (if the project qualifies), we are permitted to claim a tax credit based on the power produced from a geothermal power plant. These production-based credits, which in the first quarter of 2014 were 2.3 cents per kWh, are adjusted annually for inflation and may be claimed for ten years on the electricity produced by the project and sold to third parties after the project is placed in service. The owner of the power plant may not claim both the 30% tax credit and the production-based tax credit. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward. If we claim the ITC, our "tax basis" in the plant that we can recover through depreciation must be reduced by half of the ITC. If we claim the PTC, there is no reduction in the tax basis for depreciation. Companies that placed qualifying renewable energy facilities in service during 2009, 2010 or 2011 or that began construction of qualifying renewable energy facilities during 2009, 2010 or 2011 and placed them in service by December 31, 2013, may choose to apply for a cash grant from the U.S. Treasury in an amount equal to the ITC. Likewise, the tax basis for depreciation will be reduced by 50% of the cash grant received. Under the ARRA, the U.S. Treasury is instructed to pay the cash grant within 60 days of the application or the date on which the qualifying facility is placed in service.

Ormat Systems received “Benefited Enterprise” status under Israel’s Law for Encouragement of Capital Investments, 1959 (the Investment Law), with respect to two of its investment programs. As a Benefited Enterprise, Ormat Systems was exempt from Israeli income taxes with respect to income derived from the first benefited investment for a period of two years that started in 2004, and thereafter such income was subject to reduced Israeli income tax rates, which could not exceed 25% for an additional five years until 2010. Ormat Systems was also exempt from Israeli income taxes with respect to income derived from the second benefited investment for a period of two years that started in 2007. Thereafter, such income is subject to reduced Israeli income tax rates which cannot exceed 25% for an additional five years until 2013 (see also below). These benefits are subject to certain conditions, including among other things, that all transactions between Ormat Systems and its affiliates are done on an arm’s length basis and that the management of Ormat Systems will be located in, and the control will be conducted from, Israel during the entire period of the tax benefits. A change in control of Ormat Systems would need to be reported to the Israel Tax Authority in order for Ormat Systems to maintain the tax benefits. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax will apply to all qualified income of certain industrial companies, as opposed to the previous law’s incentives that are limited to income from a “Benefited Enterprise” during their benefits period. According to the amendment, the uniform tax rate applicable to the zone where the production facilities of Ormat Systems are located would be 15% in 2011 and 2012, 12.5% in 2013 and 16% in 2014 and thereafter. Under the transitory provisions of the new legislation, Ormat Systems had the option either to irrevocably comply with the new law while waiving benefits provided under the previous law or to continue to comply with the previous law during the transition period, with an option to move from the previous law to the new law at any stage. Ormat Systems decided to irrevocably comply with the new law starting in 2011.

ITEM 3. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

We incorporate by reference the information appearing under “Exposure to Market Risks” and “Concentration of Credit Risk” in Part I, Item 2 of this quarterly report on Form 10-Q.

ITEM 4. *CONTROLS AND PROCEDURES*

a. Evaluation of disclosure controls and procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures to ensure that the information required to be disclosed in our filings pursuant to Rule 13a-15 under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms and to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on that evaluation, as of September 30, 2014, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the

Securities Exchange Act of 1934, as amended) were effective.

b. Changes in internal controls over financial reporting

There were no changes in our internal controls over financial reporting in the third quarter of 2014 that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In December 2012, Laborers' International Union of North America Local Union No. 783 ("LiUNA"), an organized labor union, filed a petition in Mono County Superior Court, naming Mono County, California and the Company as defendant and real party in interest, respectively. The petitioners' brought this action to challenge the November 13, 2012 decision of the Mono County Board of Supervisors in adopting Resolutions No. 12-78, denying petitioners' administrative appeal of the Planning Commission's approval of Conditional Use Permit ("CUP"), adoption of findings under the California Environmental Quality Act ("CEQA") and adoption of the final environmental impact report ("EIR") for the Mammoth enhancement. The Company has successfully defended itself against the petition, which has been denied by the court.

On July 8, 2014, Global Community Monitor, LiUNA, and two residents of Bishop, California filed a complaint in the United States District Court for the Eastern District of California, alleging that Mammoth Pacific, L.P., Ormat Technologies, Inc. and Ormat Nevada, Inc. are operating three geothermal generating plants in Mammoth Lakes, California (MP-1; MP-II and PLES-I) in violation of the federal Clean Air Act ("CAA") and Great Basin Unified Air Pollution Control District ("District") rules. The Company believes the complaint is without merit, and intends to vigorously defend itself against the allegations set forth in the complaint and to take all necessary legal action to have the complaint dismissed. Filing of the complaint in and of itself does not have any immediate adverse implications for the Mammoth plants.

In January 2014, we learned that two former employees alleged in a "qui tam" complaint filed in the United States District Court for the Southern District of California that the Company submitted fraudulent applications and certifications to obtain grants. The United States Department of Justice has declined to intervene. The former employees have proceeded on their own and served the Company with their initial complaint in April 2014, and then filed an amended complaint in May 2014. The Company is investigating, and is defending against the amended complaint. This includes that, pursuant to the Company's motion to move the venue of the proceeding, the file was reassigned from the United States District Court for the Southern District of California to the District of Nevada. In addition, the Company has filed a motion to dismiss the amended complaint, in response to which the complainants have filed responses, and the United States has filed a statement of interest regarding the Company's claim that the False Claims Act's "Tax Bar" excludes such Act's application to the Company, and urged the court to reject the Company's argument, while continuing to take no position as to the overall sufficiency of the complainants' complaint. The motion to dismiss is pending before the Nevada United States District Court. The Company continues to believe that the allegations of the lawsuit have no merit, and we will continue to defend ourselves vigorously.

In addition, from time to time, the Company is named as a party in various other lawsuits, claims and other legal and regulatory proceedings that arise in the ordinary course of its business. These actions typically seek, among other things, compensation for alleged personal injury, breach of contract, property damage, punitive damages, civil penalties or other losses, or injunctive or declaratory relief. With respect to such lawsuits, claims and proceedings, the Company accrues reserves when a loss is probable and the amount of such loss can be reasonably estimated. It is the opinion of the Company's management that the outcome of these proceedings, individually and collectively, will not be material to the Company's consolidated financial statements as a whole.

ITEM 1A. *RISK FACTORS*

A comprehensive discussion of our risk factors is included in the "Risk Factors" section of our annual report on Form 10-K for the year ended December 31, 2013 filed with the SEC on February 28, 2014.

ITEM 2. *UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS*

There were no unregistered sales of equity securities of the Company during the third quarter of 2014.

ITEM 3. ***DEFAULTS UPON SENIOR SECURITIES***

None.

ITEM 4. ***MINE SAFETY DISCLOSURES***

Not applicable

ITEM 5. ***OTHER INFORMATION***

Not applicable.

ITEM 6. EXHIBITS

We hereby file, as exhibits to this quarterly report, those exhibits listed on the Exhibit Index immediately following the signature page hereto.

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.

ORMAT TECHNOLOGIES, INC.

By: /s/ DORON BLACHAR
Name: Doron Blachar
Title: Chief Financial Officer

Date: November 6, 2014

EXHIBIT INDEX

Exhibit No.	**Document**
3.1	Second Amended and Restated Certificate of Incorporation, incorporated by reference to Exhibit 3.1 to Ormat Technologies, Inc. Registration Statement on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on July 20, 2004.
3.2	Fourth Amended and Restated By-laws, incorporated by reference to Exhibit 3.2 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on January 2, 2013.

3.3	Amended and Restated Limited Liability Company Agreement of OPC LLC dated June 7, 2007, by and among Ormat Nevada Inc., Morgan Stanley Geothermal LLC, and Lehman-OPC LLC, incorporated by reference to Exhibit 3.1 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on June 13, 2007.
3.4	Limited Liability Company Agreement of ORTP, LLC dated as of January 24, 2013, between Ormat Nevada, Inc., a wholly-owned subsidiary of Ormat Technologies, Inc., and JPM Capital Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies,

	Inc. Current Report on Form 8-K to the Securities and Exchange Commission on January 30, 2013.
4.1	Form of Common Share Stock Certificate, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc. Registration Statement on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on July 20, 2004.
4.2	Form of Preferred Share Stock Certificate, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc. Registration Statement on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on July 20, 2004.
4.3	Form of Rights Agreement by

	and between Ormat Technologies, Inc. and American Stock Transfer & Trust Company, incorporated by reference to Exhibit 4.3 to Ormat Technologies, Inc. Registration Statement Amendment No. 2 on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on October 22, 2004.
4.4	Indenture for Senior Debt Securities, dated as of January 16, 2006, between Ormat Technologies, Inc. and Union Bank of California, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc. Registration Statement Amendment No. 1 on Form S-3 (File No. 333-131064) to the Securities and Exchange

	Commission on January 26, 2006.
4.5	Indenture for Subordinated Debt Securities, dated as of January 16, 2006, between Ormat Technologies, Inc. and Union Bank of California, incorporated by reference to Exhibit 4.3 to Ormat Technologies, Inc. Registration Statement Amendment No. 1 on Form S-3 (File No. 333-131064) to the Securities and Exchange Commission on January 26, 2006.
4.6	Deed of Trust, dated as of August 3, 2010, between Ormat Technologies, Inc. and Ziv Haft Trust Company Ltd., as trustee, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and

	Exchange Commission on February 2, 2011.
4.7	Addendum, dated as of January 27, 2011, to the Deed of Trust, dated as of August 3, 2010, between Ormat Technologies, Inc. and Ziv Haft Trust Company Ltd., as trustee, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on February 2, 2011.
4.8	Form of Bond issued pursuant to the Deed of Trust, dated as of August 3, 2010 (as amended or supplemented), between Ormat Technologies, Inc. and Ziv Haft Trust Company Ltd., as trustee, incorporated by reference to Exhibit 4.3 to Ormat Technologies,

	Inc. Current Report on Form 8-K to the Securities and Exchange Commission on February 2, 2011.
4.9	Second Addendum, dated as of February 11, 2011, to the Deed of Trust, dated as of August 3, 2010 (as amended or supplemented), between Ormat Technologies, Inc. and Ziv Haft Trust Company Ltd., as trustee, incorporated by reference to Exhibit 4.7 to Ormat Technologies, Inc. Quarterly Report on Form 10-Q to the Securities and Exchange Commission on May 6, 2011.
4.10	Indenture of Trust and Security Agreement, dated September 23, 2011, among OFC 2 LLC, ORNI 15 LLC, ORNI 39 LLC, ORNI 42 LLC, HSS II, LLC, and

Wilmington Trust Company, as Trustee and Depository, incorporated by reference to Exhibit 4.8 to Ormat Technologies, Inc. Quarterly Report on Form 10-Q to the Securities and Exchange Commission on November 4, 2011.

58

4.11	Third Addendum, dated as of December 1, 2011, to a Deed of Trust, dated as of August 3, 2010 as amended on January 31, 2011 (effective as of January 27, 2011) and on February 13, 2011, between Ormat Technologies, Inc. and Mishmeret — Trusts Services Company Ltd. (formerly Ziv Haft Trust Company Ltd.), as trustee, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on December 1, 2011.
31.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, furnished herewith.
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, furnished herewith.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.