ORMAT TECHNOLOGIES, INC.
Form 10-Q
November 06, 2013

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, 2013

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 incorporation or organization)	*(I.R.S. Employer 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 Smaller reporting company

(Do not check if a 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, 2013, the number of outstanding shares of common stock, par value $0.001 per share, was 45,453,801.

ORMAT TECHNOLOGIES, INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2013

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, 2013	**December 31,** 2012 **As Revised**
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$35,435	$66,628
Short-term bank deposit	—	3,010
Restricted cash, cash equivalents and marketable securities (all related to variable interest entities ("VIEs"))	84,197	76,537
Receivables:		
Trade	60,526	55,680
Related entity	442	373
Other	24,643	8,632
Due from Parent	373	311
Inventories	20,396	20,669
Costs and estimated earnings in excess of billings on uncompleted contracts	36,201	9,613
Deferred income taxes	162	637
Prepaid expenses and other	36,724	34,144
Total current assets	299,099	276,234
Unconsolidated investments	5,419	2,591
Deposits and other	31,110	36,187
Deferred income taxes	15,966	21,283
Deferred charges	34,635	35,351
Property, plant and equipment, net ($1,310,022 and $1,188,721 related to VIEs, respectively)	1,383,353	1,252,873
Construction-in-process ($99,806 and $253,775 related to VIEs, respectively)	335,915	396,141
Deferred financing and lease costs, net	29,806	31,371
Intangible assets, net	33,032	35,492

Total assets	$2,168,335	$2,087,523
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$83,751	$98,001
Deferred income taxes	20,428	20,392
Billings in excess of costs and estimated earnings on uncompleted contracts	12,708	25,408
Current portion of long-term debt:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	30,059	28,231
Other loans	18,288	11,453
Full recourse	28,875	28,649
Total current liabilities	194,109	212,134
Long-term debt, net of current portion:		
Limited and non-recourse (all related to VIEs):		
Senior secured notes	286,786	312,926
Other loans	272,710	242,815
Full recourse:		
Senior unsecured bonds (plus unamortized premium based upon 7% of $1,205)	250,674	250,904
Other loans	64,414	82,344
Revolving credit lines with banks	123,288	73,606
Liability associated with sale of tax benefits	65,402	51,126
Deferred lease income	64,217	66,398
Deferred income taxes	52,233	45,059
Liability for unrecognized tax benefits	8,878	7,280
Liabilities for severance pay	23,642	22,887
Asset retirement obligation	20,436	19,289
Other long-term liabilities	4,576	5,148
Total liabilities	1,431,365	1,391,916
Commitments and contingencies (Note 10)		
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 45,453,801 shares issued and outstanding as of September 30, 2013 and December 31, 2012	46	46
Additional paid-in capital	737,125	732,140
Accumulated deficit	(13,066)	(44,326)
Accumulated other comprehensive income	527	651
	724,632	688,511
Noncontrolling interest	12,338	7,096
Total equity	736,970	695,607
Total liabilities and equity	$2,168,335	$2,087,523

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND

COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
	(Dollars in thousands, except per share data)		(Dollars in thousands, except per share data)	
Revenues:				
Electricity	$ 88,994	$ 77,612	$ 245,005	$ 238,837
Product	41,755	54,685	157,329	149,616
Total revenues	130,749	132,297	402,334	388,453
Cost of revenues:				
Electricity	61,356	59,924	175,085	172,785
Product	29,637	42,130	110,335	108,575
Total cost of revenues	90,993	102,054	285,420	281,360
Gross margin	39,756	30,243	116,914	107,093
Operating expenses:				
Research and development expenses	838	1,436	3,446	3,948
Selling and marketing expenses	2,575	3,346	17,861	12,752
General and administrative expenses	6,546	6,132	20,264	20,163
Impairment charge	—	7,264	—	7,264
Write-off of unsuccessful exploration activities	—	—	—	1,919
Operating income	29,797	12,065	75,343	61,047
Other income (expense):				
Interest income	742	280	870	1,004
Interest expense, net	(18,459)	(15,400)	(51,826)	(44,541)
Foreign currency translation and transaction gains (losses)	1,258	615	3,844	(1,127)
Income attributable to sale of tax benefits	5,027	2,311	14,342	7,417
Other non-operating income, net	137	215	1,583	344
Income before income taxes and equity in losses of investees	18,502	86	44,156	24,144
Income tax provision	(5,201)	(1,088)	(15,028)	(10,148)
Equity in losses of investees	(158)	(1,245)	(149)	(1,542)
Income (loss) from continuing operations	13,143	(2,247)	28,979	12,454
Discontinued operations:				
Income from discontinued operations (including gain on disposal of $0, $0,	—	2,123	5,311	4,875

$3,646 and $0, respectively)				
Income tax provision	—	(391)	(614)	(1,097)
Total income from discontinued operations	—	1,732	4,697	3,778
Net income (loss)	13,143	(515)	33,676	16,232
Net income attributable to noncontrolling interest	(193)	(67)	(600)	(278)
Net income (loss) attributable to the Company's stockholders	$ 12,950	$ (582)	$ 33,076	$ 15,954
Comprehensive income (loss):				
Net income (loss)	13,143	(515)	33,676	16,232
Other comprehensive income (loss), net of related taxes:				
Amortization of gains or losses in respect of derivative instruments designated for cash flow hedge	(40)	(47)	(124)	(140)
Change in fair value of marketable securities available-for-sale	—	262	—	242
Comprehensive income (loss)	13,103	(300)	33,552	16,334
Comprehensive income attributable to noncontrolling interest	(193)	(67)	(600)	(278)
Comprehensive income (loss) attributable to the Company's stockholders	$ 12,910	$ (367)	$ 32,952	$ 16,056
Earnings (loss) per share attributable to the Company's stockholders:				
Basic:				
Income (loss) from continuing operations	$ 0.29	$ (0.05)	$ 0.62	$ 0.27
Discontinued operations	—	0.04	0.10	0.08
Net income (loss)	$ 0.29	$ (0.01)	$ 0.72	$ 0.35
Diluted:				
Income (loss) from continuing operations	$ 0.28	$ (0.05)	$ 0.62	$ 0.27
Discontinued operations	—	0.04	0.10	0.08
Net income (loss)	$ 0.28	$ (0.01)	$ 0.72	$ 0.35
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:				
Basic	45,438	45,431	45,433	45,431
Diluted	45,494	45,431	45,454	45,438
Dividend per share declared	$ 0.04	$ 0.04	$ 0.08	$ 0.08

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							
	Common Stock							
	Shares	**Amount**	**Additional** Paid-in Capital	**Retained** Earnings (Accumulated Deficit)	**Accumulated** Other Comprehensive Income	**Total**	**Non-controlling** Interest	**Total** Equity
	(Dollars in thousands, except per share data)							
Balance at December 31, 2011	45,431	$ 46	$ 725,746	$ 172,331	$ 595	$ 898,718	$ 7,926	$ 906,644
Stock-based compensation	—	—	4,837	—	—	4,837	—	4,837
Cash paid to noncontrolling interest	—	—	—	—	—	—	(1,025)	(1,025)
Cash dividend paid, $0.08 per share	—	—	—	(3,636)	—	(3,636)	—	(3,636)
Net income	—	—	—	15,954	—	15,954	278	16,232
Other comprehensive income (loss), net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $88)	—	—	—	—	(140)	(140)	—	(140)
Change in fair value of marketable securities available-for-sale (net of related tax of $0)	—	—	—	—	242	242	—	242
Balance at September 30, 2012	45,431	$ 46	$ 730,583	$ 184,649	$ 697	$ 915,975	$ 7,179	$ 923,154
Balance at December 31, 2012	45,431	$ 46	$ 732,140	$ (44,326)	$ 651	$ 688,511	$ 7,096	$ 695,607
Stock-based compensation	—	—	4,548	—	—	4,548	—	4,548
Cash paid to noncontrolling interest	—	—	—	—	—	—	(509)	(509)
	—	—	—	(1,816)	—	(1,816)	—	(1,816)

Cash dividend paid, $0.04 per share								
Exercise of options by employees	23	—	437	—	—	437	—	437
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 income, net of related taxes:								
Amortization of gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $76)	—	—	—	—	(124)	(124)	—	(124)
Balance at September 30, 2013	45,454	$ 46	$ 737,125	$ (13,066)	$ 527	$ 724,632	$ 12,338	$ 736,970

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2013	**2012**
	(Dollars in thousands)	
Cash flows from operating activities:		
Net income	$33,676	$16,232
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	70,911	75,812
Amortization of premium from senior unsecured bonds	(231)	(231)
Accretion of asset retirement obligation	1,147	1,264
Stock-based compensation	4,548	4,837
Amortization of deferred lease income	(2,014)	(2,014)
Income attributable to sale of tax benefits, net of interest expense	(6,621)	(2,775)
Equity in losses of investees	149	442
Mark-to-market of derivative instruments	3,487	—
Write-off of unconsolidated investment	—	1,100
Write-off of unsuccessful exploration activities	—	1,919
Impairment charge	—	7,264
Loss (gain) on severance pay fund asset	(399)	332
Gain on sale of a subsidiary	(3,646)	—
Deferred income tax provision	14,235	5,894
Liability for unrecognized tax benefits	1,598	1,264
Deferred lease revenues	(167)	110
Other	(819)	—
Changes in operating assets and liabilities:		
Receivables	(23,181)	(29,742)
Costs and estimated earnings in excess of billings on uncompleted contracts	(26,588)	(3,738)
Inventories	273	(5,245)
Prepaid expenses and other	(6,175)	(12,825)
Deposits and other	4,296	(5,356)
Accounts payable and accrued expenses	(21,449)	9,523
Due from/to related entities, net	(69)	(64)
Billings in excess of costs and estimated earnings on uncompleted contracts	(12,700)	(558)
Liabilities for severance pay	1,068	271
Other long-term liabilities	959	(1,396)
Due from/to Parent	(62)	64
Net cash provided by operating activities	32,226	62,384
Cash flows from investing activities:		
Marketable securities, net	—	18,763
Short-term deposit	3,010	(3,008)

Net change in restricted cash, cash equivalents and marketable securities	(7,660)	(775)
Cash received from sale of a subsidiary	7,699	—
Capital expenditures	(144,637)	(186,332)
Cash grant received	14,685	119,199
Investment in unconsolidated companies	(2,467)	(1,260)
Increase (decrease) in severance pay fund asset, net of payments made to retired employees	1,172	(198)
Net cash used in investing activities	(128,198)	(53,611)
Cash flows from financing activities:		
Proceeds from issuance of senior unsecured bonds	—	1,171
Proceeds from long-term loans	45,000	—
Proceeds from exercise of options by employees	437	—
Proceeds from the sale of limited liability company interest in ORTP, LLC, net of transaction costs	31,376	—
Purchase of OFC Senior Secured Notes	(11,888)	—
Proceeds from revolving credit lines with banks	2,170,287	2,134,887
Repayment of revolving credit lines with banks	(2,120,605)	(2,161,462)
Repayments of long-term debt	(37,480)	(28,927)
Cash paid to non-controlling interest	(10,184)	(10,991)
Deferred debt issuance costs	(348)	(2,177)
Cash dividends paid	(1,816)	(3,636)
Net cash provided by (used in) financing activities	64,779	(71,135)
Net change in cash and cash equivalents	(31,193)	(62,362)
Cash and cash equivalents at beginning of period	66,628	99,886
Cash and cash equivalents at end of period	$35,435	$37,524
Supplemental non-cash investing and financing activities:		
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$7,744	$(18,119)
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, 2013, the consolidated results of operations and comprehensive income (loss) for the three and nine-month periods ended September 30, 2013 and 2012 and the consolidated cash flows for the nine-month periods ended September 30, 2013 and 2012.

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 period ended September 30, 2013 are not necessarily indicative of the results to be expected for the year ending December 31, 2013.

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, 2012. The condensed consolidated balance sheet data as of December 31, 2012 was derived from the audited consolidated financial statements for the year ended December 31, 2012, 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.

Revision of previously issued financial statements

The Company identified an error in the second quarter of 2013 related to the calculation and presentation of income tax provision and the related deferred tax asset for the year ended December 31, 2012 and the three months ended March 31, 2013, which was a direct result of the deferred tax effects of the non-cash asset impairment charge recorded in the fourth quarter of 2012. The Company understated the valuation allowance against the U.S. deferred tax assets by $32.7 million and $3.1 million at December 31, 2012 and March 31, 2013, respectively. As a result, for the year ended December 31, 2012 the Company revised the valuation allowance by $32.7 million, of which $26.1 million was recorded against property, plant and equipment where the Company recognized the deferred tax effects of grants received during 2012 and the remaining $6.6 million to the income tax provision. For the three months ended March 31, 2013, the Company revised the valuation allowance by an additional $3.1 million which also increased the tax provision for the period by the same amount.

The Company assessed the materiality of this error in accordance with the SEC's Staff Accounting Bulletin 99 and concluded that the previously issued financial statements were not materially misstated. However, if the entire correction of the error was recorded during the second quarter of fiscal 2013, the impact would be significant to the quarter ended June 30, 2013. In accordance with the SEC's Staff Accounting Bulletin 108, the Company corrected these errors by revising the affected financial statements previously included in the Company's 2012 Annual Report on Form 10-K and March 31, 2013 Quarterly Report on Form 10-Q.

This revision had no impact on the Company's revenues, gross margin, operating income (loss), income (loss) before taxes and equity income (loss) of investees. There was also no impact on the Company's consolidated net operating, investing or financing cash flows; however, the revisions impacted line items within the balance sheet at December 31, 2012 and March 31, 2013 and cash flows from operating activities for the year ended December 31, 2012 and the three months ended March 31, 2013. The revision impacted the Company income tax benefit (provision), net income (loss) from continuing operations, net income (loss) attributable to the Company's stockholders, comprehensive income (loss) and earnings (loss) per share ("EPS") in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2012 and the three months ended March 31, 2013.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

The consolidated statement of operations and comprehensive income (loss), consolidated balance sheet, and consolidated statement of cash flows for the year ended December 31, 2012 will be revised in the Company's 2013 Annual Report on Form 10-K and for the three months ended March 31, 2013 will be revised to correct the errors described above prospectively in the quarterly report on Form 10-Q for the first quarter of 2014.

The effect of the revision on the line items within the Company's consolidated balance sheet as of December 31, 2012 is as follows:

	As of December 31, 2012		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Deferred income taxes	$53,989	$ (32,706)	$21,283
Property, plant and equipment, net	1,226,758	26,115	1,252,873
Total assets	2,094,114	(6,591)	2,087,523
Accumulated deficit	(37,735)	(6,591)	(44,326)
Total equity	702,189	(6,591)	695,607
Total liabilities and equity	2,094,114	(6,591)	2,087,523

The effect of the revision on the line items within the Company's consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2012 is as follows:

	Year Ended December 31, 2012		
	As reported	Adjustment	As revised
	(Dollars in thousands, except per share data)		
Income tax benefit (provision)	$3,500	$ (6,591)	$(3,091)
Loss from continuing operations	(206,016)	(6,591)	(212,607)
Net loss	(206,016)	(6,591)	(212,607)

Net loss attributable to the Company's stockholders	$(206,430)	$ (6,591)	$(213,021)
Comprehensive loss	(205,960)	(6,591)	(212,551)
Comprehensive loss attributable to the Company's stockholders	$(206,374)	$ (6,591)	$(212,965)
Loss per share attributable to the Company's stockholders:			
Basic and diluted	$(4.54)	$ (0.15)	$(4.69)

The effect of the revision on the line items within the Company's consolidated statements of cash flows for the year ended December 31, 2012 is as follows:

	Year Ended December 31, 2012		
	As reported	**Adjustment**	**As revised**
	(Dollars in thousands)		
Cash flows from operating activities:			
Net loss	$(206,016)	$ (6,591)	$(212,607)
Deferred income tax provision (benefit)	(11,327)	6,591	(4,736)
Net cash provided by operating activities	$89,471	$ -	$89,471

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

The effect of the revision on the line items within the Company's consolidated balance sheet as of March 31, 2013 is as follows:

	As of March 31, 2013		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Deferred income taxes	$52,939	$ (35,758)	$17,181
Property, plant and equipment, net	1,207,410	26,115	1,233,525
Total assets	2,143,568	(9,643)	2,133,925
Accumulated deficit	(39,717)	(9,643)	(49,360)
Total equity	706,519	(9,643)	696,876
Total liabilities and equity	2,143,568	(9,643)	2,133,925

The effect of the revision on the line items within the Company's consolidated statements of operations and comprehensive income (loss) for the three months ended March 31, 2013 is as follows:

	Three Months Ended March 31, 2013		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Income tax benefit (provision)	$(1,217)	$ (3,052)	$(4,269)
Loss from continuing operations	(1,897)	(3,052)	(4,949)
Net loss	(1,897)	(3,052)	(4,949)
Net loss attributable to the Company's stockholders	$(1,982)	$ (3,052)	$(5,034)
Comprehensive loss:			
Net loss	(1,897)	(3,052)	(4,949)
Comprehensive loss	(1,939)	(3,052)	(4,991)
Comprehensive loss attributable to the Company's stockholders	$2,024	$ (3,052)	$(5,076)
Loss per share attributable to the Company's stockholders:			
Basic and diluted	$(0.04)	$ (0.07)	$(0.11)

The effect of the revision on the line items within the Company's consolidated statements of cash flows for the three months ended March 31, 2013 is as follows:

	Three Months Ended March 31, 2013		
	As reported	Adjustment	As revised
	(Dollars in thousands)		
Cash flows from operating activities:			
Net loss	$(1,897)	$ (3,052)	$(4,949)
Deferred income tax provision	668	3,052	3,720
Net cash provided by operating activities	$18,216	$ -	$18,216

Other comprehensive income

For the nine months ended September 30, 2013 and 2012, the Company classified $124,000 and $140,000, respectively, from other comprehensive income, of which $200,000 and $228,000, respectively, were recorded to reduce interest expense and $76,000 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, 2013 and 2012, the Company reclassified out $40,000 and $47,000, respectively, from other comprehensive income, of which $65,000 and $76,000, respectively, were recorded to reduce interest expense and $25,000 and $29,000, respectively, were recorded against the income tax provision, in the condensed consolidated statements of operations and comprehensive income.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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.

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, 2013 and December 31, 2012, the Company had deposits totaling $14,065,000 and $41,231,000, respectively, in seven U.S. financial institutions that were federally insured up to $250,000 per account. At September 30, 2013 and December 31, 2012, the Company's deposits in foreign countries amounted to approximately $40,320,000 and $33,215,000, respectively.

At September 30, 2013 and December 31, 2012, accounts receivable related to operations in foreign countries amounted to approximately $23,272,000 and $17,606,000, respectively. At September 30, 2013 and December 31, 2012, accounts receivable from the Company's primary customers (listed below) amounted to approximately 62.0% and 45.0% of the Company's accounts receivable, respectively.

Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy, Inc.) accounted for 15.3% and 14.5% of the Company's total revenues for the three months ended September 30, 2013 and 2012, respectively, and 17.0% and 14.2% for the nine months ended September 30, 2013 and 2012, respectively.

Southern California Edison accounted for 20.9% and 20.4% of the Company's total revenues for the three months ended September 30, 2013 and 2012, respectively, and 14.9% and 19.2% for the nine months ended September 30, 2013 and 2012, respectively.

Kenya Power and Lighting Co. Ltd. accounted for 13.8% and 8.8% of the Company's total revenues for the three months ended September 30, 2013 and 2012, respectively, and 10.9% and 8.0% for the nine months ended September 30, 2013 and 2012, 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, 2013

Disclosures about Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board ("FASB") issued accounting guidance to amend the existing disclosure requirements for offsetting financial assets and liabilities to enhance current disclosures, as well as to improve the comparability of balance sheets prepared under GAAP and those prepared under International Financial Reporting Standards. In January 2013, the FASB issued additional guidance on the scope of these disclosures. The revised disclosure guidance applies to derivative instruments and securities borrowing and lending transactions that are subject to an enforceable master netting arrangement or similar agreement. The revised disclosure guidance is effective on a retrospective basis for interim and annual periods beginning January 1, 2013. As this guidance only imposes additional disclosure requirements, its adoption did not have a material impact on the Company's consolidated financial statements.

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Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the FASB updated accounting guidance to add new disclosure requirements for items reclassified out of accumulated other comprehensive income. Although the update does not change the current requirements for reporting net income or other comprehensive income in financial statements, it does require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes thereto, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. The amendments included in this guidance are required to be applied on a retrospective basis for interim and annual periods beginning January 1, 2013. As this guidance only imposes additional disclosure requirements, its adoption did not have a material impact on the Company’s consolidated financial statements.

Presentation of Unrecognized Tax Benefits

In July 2013, the 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 is to be applied prospectively to all unrecognized tax benefits that exist at the effective date, and can be applied retroactively. The Company is currently evaluating the potential impact, if any, of the adoption of this guidance on its consolidated financial statements.

NOTE 3 — INVENTORIES

Inventories consist of the following:

	September 30, 2013	December 31, 2012
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$ 10,034	$ 9,775
Self-manufactured assembly parts and finished products	10,362	10,894
Total	$ 20,396	$ 20,669

NOTE 4 — UNCONSOLIDATED INVESTMENTS

Unconsolidated investments consist of the following:

	September 30, 2013	December 31, 2012
	(Dollars in thousands)	
Sarulla	$5,419	$ 2,591

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The Sarulla Project

The Company is a 12.75% 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 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 (“PGE”), 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 will supply its Ormat Energy Converters (“OECs”) to the power plant. The supply contract has not been signed as of September 30, 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. Construction is expected to begin after the consortium obtains financing, which is expected to take approximately one year from the signing of the JOC and ESC. The first phase is scheduled to commence operation in 2016, and the remaining two phases are scheduled to be completed in stages within 18 months thereafter.

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.

Watts & More Ltd.

In December 2012, the Company acquired additional shares in Watts & More Ltd. (“W&M”) and as a result holds 60% of W&M’s outstanding ordinary shares and W&M was consolidated as of December 31, 2012.

The Company’s investment in W&M prior to its consolidation was not significant for the related period presented in these 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).

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The following table sets forth certain fair value information at September 30, 2013 and December 31, 2012 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.

	Cost or Amortized Cost at September 30, 2013	Fair Value at September 30, 2013			
		Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$67,234	$67,234	$67,234	$—	$ —
Derivatives:					
Put options on oil price[1]	—	142	—	142	—
Currency forward contracts[2]	—	2,952	—	2,952	—
Swap transaction on natural gas price[3]	—	1,353	—	1,353	—
	$67,234	$71,681	$67,234	$4,447	$ —

	Cost or Amortized Cost at December 31, 2012	Fair Value at December 31, 2012			
		Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets					
Current assets:					

Cash equivalents (including restricted cash accounts)	$54,298	$54,298	$54,298	$—	$ —
Derivatives:					
Put options on oil price(1)	—	1,842	—	1,842	—
Currency forward contracts(2)	—	1,675	—	1,675	—
Swap transaction on natural gas price(3)	—	2,804	—	2,804	—
Swap transaction on oil price(4)	—	336	—	336	—
	$54,298	$60,955	$54,298	$6,657	$ —

(1) This amount relates to derivatives which represent European put transactions 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" 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 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).

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(3) 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" 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).

(4) 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" 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).

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, 2013**	**2012**	**Nine Months Ended September 30, 2013**	**2012**
		(Dollars in thousands)		**(Dollars in thousands)**	
Put options on oil price	Electricity revenues	$(824)	$(198)	$(1,256)	$(198)
Swap transaction on oil price	Electricity revenues	—	(3,197)	(294)	1,123
Swap transactions on natural gas price	Electricity revenues	477	(421)	81	(872)
Currency forward contracts	Foreign currency translation and transaction gains (losses)	1,970	(137)	4,895	(774)
		$1,623	$(3,953)	$3,426	$(721)

On September 3, 2013, the Company entered into NGI swap contract for notional volume of approximately 4.4 million MMbtus with a bank 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 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. 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) will be settled on a cash basis. This contract will not be designated as hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the condensed consolidated statements of operations and comprehensive income (loss).

On October 17, 2013, the Company entered into NGI swap contract for notional volume of approximately 4.2 million MMbtus with a bank effective from January 1, 2014 until December 31, 2014 (see Note 15 for discussion of this contract).

On October 17, 2013, the Company entered into New York Harbor ULSD swap contract for notional volume of 275,000 barrels (“BBL”) with a bank effective from January 1, 2014 until December 31, 2014 (see Note 15 for discussion of this contract).

The Company’s financial assets measured at fair value (including restricted cash accounts) at September 30, 2013 and December 31, 2012 include short-term bank deposits and money market funds (which are included in cash equivalents). Those assets are classified within Level 1 of the fair value hierarchy because they are valued using quoted market prices in an active market.

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There were no transfers of assets or liabilities between Level 1 and Level 2 during the nine months ended September 30, 2013.

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

	Fair Value		Carrying Amount	
	September 30, 2013	December 31, 2012	September 30, 2013	December 31, 2012
	(Dollars in millions)		(Dollars in millions)	
Olkaria III loan - DEG	$44.7	$ 48.8	$43.4	$ 47.4
Olkaria III Loan - OPIC	241.4	220.0	258.8	220.0
Amatitlan loan	35.7	38.9	32.2	34.3
Senior secured notes:				
Ormat Funding LLC ("OFC")	88.5	105.0	96.2	114.1
OrCal Geothermal LLC ("OrCal")	74.8	77.3	74.0	76.5
OFC 2 LLC ("OFC 2")	121.3	131.2	146.6	150.5
Senior unsecured bonds	265.8	273.2	250.7	250.9
Loans from institutional investors	22.2	27.7	21.5	27.0

The fair value of OFC Senior Secured Notes is determined using observable market prices as these securities are traded. The fair value of other 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 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, 2013:

	Level 1	**Level 2**	**Level 3**	**Total**
	(Dollars in millions)			
Olkaria III loan - DEG	$—	$—	$44.7	$44.7
Olkaria III loan - OPIC	—	—	241.4	241.4
Amatitlan loan	—	—	35.7	35.7
Senior secured notes:				
OFC	—	88.5	—	88.5
OrCal	—	—	74.8	74.8
OFC 2	—	—	121.3	121.3
Senior unsecured bonds	—	—	265.8	265.8
Loan from institutional investors	—	—	22.2	22.2
Other long-term debt	—	28.3	—	28.3
Revolving lines of credit	—	123.3	—	123.3
Deposits	21.0	—	—	21.0

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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 shares 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 (“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 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. Upon exercise, SARs entitle the recipient to receive shares of common stock equal to the increase in the fair market value of the Company’s common stock from the grant date to the date of exercise. The shares of common stock will be issued upon exercise of options or SARs from the Company’s authorized share capital.

On April 3, 2013, the Company granted its Chief Financial Officer 120,000 SARs under the 2012 Incentive Plan. The exercise price of each SAR is $20.54, which represented the fair market value of the Company's common stock on the date of grant. Such SARs will expire six years from the date of grant, and will vest in equal annual installments over a period of four years from the grant date.

The fair value of each SAR on the date of grant was $5.64. The Company calculated the fair value of each SAR on the date of grant using the Black-Scholes valuation model based on the following assumptions:

Risk-free interest rates	0.57%
Expected lives (in years)	4.25
Dividend yield	0.80%
Expected volatility	35.76%
Forfeiture rate	0.00%

On June 4, 2013, the Company granted its employees 1,150,100 SARs under the 2012 Incentive Plan. The exercise price of each SAR is $23.34, which represented the fair market value of the Company's common stock on the date of grant. Such SARs will expire six years from the date of grant, and will vest fully after four years starting from the grant date, 25% at the end of the second year, 25% at the end of the third year, and 50% at the end of the fourth year.

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The fair value of each SAR on the date of grant was $7.21. The Company calculated the fair value of each SAR on the date of grant using the Black-Scholes valuation model based on the following assumptions:

Risk-free interest rates	0.77%
Expected lives (in years)	4.625
Dividend yield	0.70%
Expected volatility	38.13%
Forfeiture rate	6.37%

During the third quarter of 2013, the Company evaluated the trends in the stock-based award forfeiture rate and determined that the actual rate is 7.46%. This represents an increase of 1.09% from the estimate made a year earlier in the third quarter of 2012. As a result of the estimated forfeiture rate increase, the stock based compensation expense decreased by an immaterial amount.

NOTE 7 — INTEREST EXPENSE, NET

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2013	**2012**	**2013**	**2012**
	(Dollars in thousands)		**(Dollars in thousands)**	
Interest related to sale of tax benefits	$3,479	$1,580	$9,233	$5,140
Other interest expense	16,811	16,301	48,820	48,968
Less — amount capitalized	(1,831)	(2,481)	(6,227)	(9,567)
	$18,459	$15,400	$51,826	$44,541

NOTE 8 — EARNINGS PER SHARE

Basic earnings per share attributable to the Company’s stockholders 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		**Nine Months Ended**	
	September 30, 2013	**2012**	**September 30, 2013**	**2012**
	(In thousands)		**(In thousands)**	
Weighted average number of shares used in computation of basic earnings per share	45,438	45,431	45,433	45,431
Add:				
Additional shares from the assumed exercise of employee stock-based awards	56	—	21	7
Weighted average number of shares used in computation of diluted earnings per share	45,494	45,431	45,454	45,438

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 4,999,298 and 5,423,548 for the three months ended September 30, 2013 and 2012, respectively, and 5,312,238 and 5,663,796 for the nine months ended September 30, 2013 and 2012, respectively.

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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 table:

	Electricity	Product	Consolidated
	(Dollars in thousands)		
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
Three Months Ended September 30, 2012:			
Net revenues from external customers	$77,612	$54,685	$ 132,297
Intersegment revenues	—	11,063	11,063
Operating income	4,681	7,384	12,065
Segment assets at period end *	2,150,533	107,830	2,258,363
* Including unconsolidated investments	2,496	980	3,476

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

Nine Months Ended September 30, 2012:			
Net revenues from external customers	$238,837	$149,616	$388,453
Intersegment revenues	—	32,970	32,970
Operating income	35,980	25,067	61,047
Segment assets at period end *	2,150,533	107,830	2,258,363
* Including unconsolidated investments	2,496	980	3,476

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
	(Dollars in thousands)		(Dollars in thousands)	
Operating income	$29,797	$12,065	$75,343	$61,047
Interest income	742	280	870	1,004
Interest expense, net	(18,459)	(15,400)	(51,826)	(44,541)
Foreign currency translation and transaction gains (losses)	1,258	615	3,844	(1,127)
Income attributable to sale of tax benefits	5,027	2,311	14,342	7,417
Other non-operating income, net	137	215	1,583	344
Total income, before income taxes, discontinued operations and equity in losses of investees	$18,502	$86	$44,156	$24,144

NOTE 10 — COMMITMENTS AND CONTINGENCIES

On December 24, 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 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 I replacement project. The petition asked the court to set aside the approval of the CUP and adoption of the EIR and cause a new EIR to be prepared and circulated.

The Company believes that the petition is without merit and intends to respond and take necessary legal action to dismiss the proceedings. The Company responded to LiUNA's petition. Filing of the petition in and of itself does not have any immediate adverse implications for the Mammoth enhancement.

On January 4, 2012, the California Unions for Reliable Energy (“CURE”) filed a petition in Alameda Superior Court, naming the California Energy Commission (“CEC”) and the Company as defendant and real party in interest, respectively. The petition asked the court to order the CEC to vacate its decision which denied, with prejudice, the complaint filed by CURE against the Company with the CEC. The CURE complaint alleged that the Company’s North Brawley Project and East Brawley Project both exceed the CEC’s 50 MW jurisdictional threshold and therefore are subject to the CEC licensing authority rather than Imperial County licensing authority. In addition, the CURE petition asks the court to investigate and halt any ongoing violation of the Warren Alquist Act by the Company, and to award CURE attorney’s fees and costs. As to North Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider provisions of the County permit for North Brawley, which CURE contends authorizes the Company to build a generating facility with a number of OECs capable of generating more than 50 MW. As to East Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider the conditional use permit application for East Brawley, which CURE contends shows that the Company requested authorization to build a facility with a number of OECs capable of generating more than 50 MW.

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The court held two hearings and on November 15, 2012, CURE’s petition was denied. Any appeal of the court's decision had to be filed by March 4, 2013, and no appeal was filed.

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, 2013 and 2012 was 28.1% and 1265.1%, respectively. The Company’s effective tax rate for the nine months ended September 30, 2013 and 2012 was 34.0% and 42.0%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the three and nine months ended September 30, 2013 primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions, offset by (i) lower tax rates in Israel; and (ii) 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 nine months ended September 30, 2013 and 2012, was $1,890,000 and $3,429,000, respectively. The effect of the tax credit and tax exemption for the three months ended September 30, 2013 and 2012, was $495,000 and $853,000, respectively.

At December 31, 2012, the Company had U.S. federal net operating loss (“NOLs”) carryforwards of approximately $267.6 million and state NOL carryforwards of approximately $193.4 available to reduce future taxable income, which expire between 2021 and 2032 for federal NOLs and between 2013 and 2032 for state NOLs. Investment tax credits in the amount of $2.0 million at December 31, 2012 are available for a 20-year period and expire between 2022 and 2024. Production tax credits (“PTCs”) in the amount of $69.0 million at December 31, 2012 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, 2012 and September 30, 2013, as at those 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 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.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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 will 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 2014, and 12% in 2015 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.

In November 2012, new legislation amending the Investment Law was enacted. Under the new legislation, companies that have retained earnings as of December 31, 2011 from Benefited Enterprises may elect by November 11, 2013 to pay a reduced corporate tax rate set forth in the new legislation on such undistributed income and distribute a dividend from such income without being required to pay additional corporate tax with respect to such income. A company that makes this election will be required to make certain investments in its Benefited Enterprise by: (i) purchasing productive assets (other than buildings); (ii) investing in research and development in Israel; and/or (iii) paying salaries of new employees (other than directors and officers of the company) of the Benefited Enterprise. The number of new employees for these purposes will be determined in comparison to the number of employees employed by the Benefited Enterprise at the end of 2011. Such investment must be made over a period of five years commencing in the tax year in which the election is made. The amount of the required investment is determined pursuant to a formula set forth in the new legislation. A company that makes the election allowed under the new legislation cannot later undo its election. As of the date of this quarterly report Ormat Systems has not yet decided whether to make such election.

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

	Nine Months Ended September 30,	
	2013	2012
	(Dollars in thousands)	
Balance at beginning of period	$7,280	$5,875
Additions based on tax positions taken in prior years	901	1,264
Additions based on tax positions taken in current year	697	—
Balance at end of period	$8,878	$7,139

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 12 — ORTP TAX MONETIZATION TRANSACTION

On January 24, 2013, Ormat Nevada entered into agreements with JP Morgan (“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 ORTP 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 approximately $8.7 million.

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.

For the three months and nine months ended September 30, 2013, the impact of the ORTP transaction was a net gain of $2.0 million and $6.1 million, respectively, on the Company's condensed consolidated statements of operations and comprehensive income (loss). For the three months and nine months ended September 30, 2013, revenues of $3.9 million and $10.3 million, respectively, were recognized in income attributable to the sale of tax benefits and a $1.9 million and $4.2 million finance charge was recognized in interest expense, for the three months and nine months ended September 30, 2013, respectively.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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 (loss) for all comparative periods presented.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in thousands)		(Dollars in thousands)	
Revenues - electricity	$—	$3,840	$4,866	$9,873
Cost of revenues - electricity:	—	1,542	2,869	4,565
Gross margin	—	2,298	1,997	5,308

Operating expenses:				
Selling and marketing expenses	—	99	192	281
General and administrative expenses	—	76	140	152
Operating income	—	2,123	1,665	4,875
Income from discontinued operations before income taxes	—	2,123	5,311	4,875
Income tax provision	—	(391)	(614)	(1,097)
Income from discontinued operations, net of taxes	$—	$1,732	$4,697	$3,778

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 14 — CASH DIVIDEND

On August 6, 2013, the Company’s Board of Directors declared, approved and authorized payment of a quarterly dividend of $1.8 million ($0.04 per share) to all holders of the Company’s issued and outstanding shares of common stock on August 19, 2013. Such dividend was paid on August 29, 2013.

NOTE 15 — SUBSEQUENT EVENTS

Swap contract on natural gas prices

On October 16, 2013, the Company entered into a NGI swap contract for notional volume of approximately 4.2 million MMbtus with a bank 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 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. 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) will be settled on a cash basis. This contract will not be designated as a hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the condensed consolidated statements of operations and comprehensive income (loss).

Swap contract on New York Harbor ULSD

On October 16, 2013, the Company entered into a New York Harbor ULSD swap contract for notional volume of 275,000 BBL with a bank 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. This contract will not be designated as a hedge transaction and will be marked to market with the corresponding gains or losses recognized within “electricity revenues” in the condensed consolidated statements of operations and comprehensive income (loss).

Cash dividend

On November 5, 2013, the Company’s Board of Directors declared, approved and authorized payment of a quarterly dividend of $1.8 million ($0.04 per share) to all holders of the Company’s issued and outstanding shares of common stock on November 20, 2013. The dividend will be payable on December 4, 2013.

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 on Form 10-Q, the words "may", "will", "could", "should", "expects", "plans", "anticipates", "believes", "estimates", "predicts", "projects", "potential", or "contemplate" or the negative o terms or other 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 on Form 10-Q 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 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 and other nature disasters;

the impact of recent and future federal and state 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 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 such as the threat or occurrence of 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 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, 2012 and any update contained herein and other risks and uncertainties detailed from time to time in our filings with the Securities and Exchange Commission; 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, 2012 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. We have expanded our activities in the Electricity Segment to include the ownership and operation of power plants that produce electricity generated by Solar PV systems that we do not manufacture; 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, 2013, our total revenues increased by 3.6% (from $388.5 million to $402.3 million) over the corresponding period in 2012.

For the nine months ended September 30, 2013, Electricity Segment revenues were $245.0 million, compared to $238.8 million for the nine months ended September 30, 2012, an increase of 2.6%, and Product Segment revenues for the nine months ended September 30, 2013 were $157.3 million, compared to $149.6 million during the nine months ended September 30, 2012, an increase of 5.2%.

During the nine months ended September 30, 2013 and 2012, our consolidated power plants generated 3,092,482 megawatt hours (MWh) and 2,876,158 MWh, respectively, an increase of 7.5%.

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, 2012, our Electricity Segment represented approximately 61.5% of our total revenues, while our Product Segment represented approximately 38.5% of our total revenues.

For the nine months ended September 30, 2013, approximately 66.0% 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 PPAs in California for each of the Ormesa complex, the Heber 1 and Heber 2 power plants in the Heber complex and G2 power plant in the Mammoth complex (the California Standard Offer #4 (SO#4) PPAs), change based primarily 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 natural gas and oil until December 31, 2014 by entering into derivatives contracts. In the third quarter of 2013, we recorded a loss of $0.3 million in electricity revenues related to these contracts.

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 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, 2013 are described below:

On October 8, 2013, we announced that we entered into an agreement for the development of the Hu'u Dompu greenfield geothermal project in Indonesia. We will develop the project through the project company Pacific Geo Energy (PAGE), in which Ormat will hold 90% and the remaining 10% will be held by the current holders of PAGE. The Hu'u Dompu project is located in West Nusa Tenggara Province on Indonesia's Sumbawa Island, and may be developed for up to 60 megawatts (MW) in three phases over the next six years.

On September 26, 2013, we entered into a Joint Development Agreement with eBay Inc. for the development of a five-megawatt REG power plant to be constructed in Utah. The Joint Development Agreement allows eBay and us to begin preliminary development work to supply cleaner electricity to eBay's new Salt Lake City-based data center while entering into negotiations for a 20-year term contract.

On September 6, 2013, we announced that we entered into a 10-year PPA with Southern California Public Power Authority (SCPPA) to deliver electricity from our Heber 1 geothermal power plant at the Heber complex in Imperial Valley, California beginning December 16, 2015. The current PPA with Southern California Edison will expire December 15, 2015. With an expected net generating capacity of 46 MW, we expect to sell the power to SCPPA at an average price of approximately $85.62 per megawatt hour over the lifetime of the agreement. The new pricing is expected to increase Heber 1 revenues in 2016 by more than $7.0 million compared to expected revenues in 2013. SCPPA members that will receive power from Heber 1 are the Los Angeles Department of Water and Power (LADWP) and the Imperial Irrigation District (IID).

On July 15, 2013, we completed the conversion of the $263.0 million in principal amount outstanding under our debt facility with Overseas Private Investment Corporation (OPIC) from a floating interest rate to a fixed interest rate. The conversion applies to both tranches of the facility, which is being used to finance the Olkaria III complex in Naivasha, Kenya. The average fixed interest rate for Tranche I, which has an outstanding balance of $81.5 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $177.4 million and matures on June 15, 2030, is 6.31%.

On June 3, 2013, we announced that our wholly owned subsidiary, Ormat Holding Corp., has sold its stake in the Momotombo Power Company (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 arrangement with the Nicaraguan owner. This amount represents a prepayment of the expected EBITDA of the plant through the scheduled expiration of the contract. As a result of the sale, we recorded an after-tax gain of approximately $3.6 million in the second quarter of 2013.

On May 2, 2013, we announced that we reached commercial operation of Plant 2 in the Olkaria III complex in Naivasha, Kenya, increasing our total worldwide generating capacity by 36 MW. The power generated in the Olkaria III complex is sold under a 20-year PPA with Kenya Power and Lighting Company Limited (KPLC). The complex generating capacity improved and it currently generates 92.4 MW, approximately 10% over the original target capacity.

On April 29, 2013, we entered into a 20-year PPA with SCPPA to deliver electricity from our Don A. Campbell (formerly Wild Rose) geothermal power plant in Mineral County, Nevada. We will sell the power to SCPPA at $99 per MWh with no annual escalation, and SCPPA will resell the power to the LADWP and Burbank Water and Power (BWP). Electricity from Don A. Campbell geothermal power plant will be transmitted to LADWP and BWP through NV Energy Inc.'s transmission system.

On April 4, 2013, Sarulla Operations Ltd. (SOL) signed a Joint Operating Contract (JOC) and Energy Sales Contract (ESC) for the 330 MW Sarulla geothermal power project in Tapanuli Utara, North Sumatra in Indonesia. We designed the plant and will supply our Ormat Energy Converters (OEC) to the power plant, as a result of which we expect to recognize revenues of approximately $254.0 million related to the equipment sales over the construction period. In addition, through our subsidiary Ormat International, Inc., we hold a 12.75% equity stake in SOL, which owns and operates the Sarulla project. Other members of the consortium include Medco Energi Internasional Tbk (Medco); Itochu Corporation (Itochu); and Kyushu Electric Power Co. Inc (Kyushu).

The consortium has started preliminary testing and development activities at the site and recently signed an engineering procurement and construction agreement (EPC) with an unrelated third party. Construction is expected to begin after the consortium obtains financing, which is expected to take approximately one year from the signing of the JOC and ESC. The first phase is scheduled to commence operation in 2016, with the remaining two phases scheduled to be completed in stages within 18 months thereafter.

The project is expected to obtain construction and term loans under a non-recourse or limited-recourse financing package of direct loans from the Japan Bank for International Cooperation (JBIC) and the Asian Development Bank (ADB), as well as loans to be provided by five commercial banks (the MLAs). The MLAs are expected to be backed by political risk guarantees from JBIC.

On April 1, 2013, we began to sell geothermal power from the G3 plant in the Mammoth Complex in California to Pacific Gas & Electric (PG&E) under a new 20 year PPA for up to 14 MW. Deliveries under a separate PPA for up to 7.5 MW of geothermal power from the G1 plant in the Mammoth complex are expected to start by the end of 2013. On March 15, 2013, we finalized the agreement with Southern California Edison (SCE), by which the current G1 and G3 SO#4 PPAs were terminated and, in connection therewith, we paid a termination fee of approximately $9.0 million in the first quarter of 2013. Under the agreement, we will continue to sell power from G2, the third plant of the Mammoth complex, under its existing PPA with SCE, with the term of the contract extended by an additional six years until early 2027.

On January 28, 2013, Ormat Nevada, our wholly owned subsidiary, and JP Morgan (JPM) entered into a tax equity partnership transaction involving certain geothermal power plants in California and Nevada. As part of the transaction, Ormat Nevada transferred the plants into ORTP, LLC (ORTP), a new wholly owned subsidiary, and sold an interest in ORTP to JPM. In connection with the closing, JPM paid to Ormat Nevada approximately $35.7 million and will make additional payments to ORTP based on the value of production tax credits (PTCs) generated by the portfolio over time that are expected to be made until December 31, 2016 and add up to approximately $8.7 million.

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 relative to fossil fuel generation. This has partly been due to increasing natural gas and oil prices during much of this period and, equally important, 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 PTC 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. The future demand for energy generated from geothermal and other renewable resources in the United States is driven by further commitment and implementation of the renewable portfolio standards as well as further introduction of tax incentives. Our operations and 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 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 and in the Solar PV sector.

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 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. Federal legislation or additional federal regulations addressing climate change are possible. In June 2013 President Barack Obama announced a new national climate action plan, directing the EPA to complete new pollution standards for both new and existing power plants. In addition, several states and regions are already addressing climate change. 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 is 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. We expect that in future years the additional demand for renewable energy from utilities in California, driven by the impact of the increase in California’s RPS, will outpace a possible reduction in general demand for energy (if any) due to the effect of economic conditions.

In June 2013, the Nevada state legislature passed three bills that were approved 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, and instead incorporates the station usage standard used by the U.S. Federal Regulatory Commission (FERC). The bill gradually cancels credits such as energy efficiency credits starting in 2015 and reduces them to zero by 2025. Finally, AB 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 20-year duration and local sales and use tax abatements for three years.

Outside of the United States in November 2012 United States, 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 African over the next 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. 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 a leading source of renewable energy in areas with commercially viable geothermal resource. 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. 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.

North America is the largest and most developed natural gas market in the world. As recently as five years ago, the region was considered to be short on supply, with an expected need to import significant volumes of liquefied natural gas (LNG) from the international gas market to balance supply with expected demand. The rise of shale gas production over the last four years has significantly changed the natural gas market landscape in North America. The unexpected growth in supply at increasingly lower costs has come at a time when the U.S. economy has been facing constrained demand growth for natural gas. The current natural gas price level has led some producers to shut-in wells and reduce output, which in turn may increase natural gas prices. Among other things, the natural gas supply growth has led to an increased interest in exporting natural gas from the U.S. in the form of LNG. Various natural gas companies and other project sponsors have recently applied and, in some cases, already received an export license to export LNG to countries with which the U.S. has a free trade agreement providing comity in trading natural gas (FTA-nations) and to other non-FTA nations. At the same time, environmentalists, regulators, natural gas companies and the public have been focusing more attention on the potential environmental impacts associated with natural gas fracking, including possible chemical leakage, ground water contamination and other effects, which may slow development in some areas. 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.

Our 25 MW PPA for the Puna complex 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 and under any other variable energy rate in PPAs that we may enter into in the future. We have entered into put and swap 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 increase volatility in revenues, net profit and certain other line items in our financial statements due to applicable accounting standards.

Our PPAs for the Ormesa complex, G2 power plant in the Mammoth complex and the Heber 1 and 2 power plants in the Heber complex 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. These PPAs may be impacted by fluctuations in natural gas prices. We have entered into swap transactions at a fixed average price of $4.0 per MMbtu in 2013 and $4.07 per MMbtu in 2014 to reduce our exposure to fluctuations in natural gas prices through December 31, 2014. Our use of derivative instruments for this purpose has increased, and likely will continue to increase volatility in revenues, net profit and certain other line items in our financial statements due to applicable accounting standards.

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, economic and financial risks, which vary by country. As of the date of this report, those risks include the partial privatization of the electricity sector in Guatemala and the political uncertainty currently prevailing in some of the countries in which we operate. Although we maintain political risk insurance for most of our foreign power plants to mitigate these risks, insurance does not provide complete coverage with respect to all such risks.

The Energy Policy Act of 2005 authorizes the FERC to 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 existing U.S. power plants significantly, as all of our current PPAs are long-term. FERC recently 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 66.0% of our Electricity revenues for the nine months ended September 30, 2013 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 2012 and 2013 we entered into swap contracts and put transactions in an attempt to reduce our exposure to fluctuations in the prices of natural gas and oil from these PPAs until December 31, 2014.

Our Electricity Segment revenues are also subject to seasonal variations, as more fully described in “Seasonality” below, and may also be affected by higher-than-average ambient temperature, which could cause a decrease in the generating capacity of our power plants, and by unplanned major maintenance activities related to our power plants.

Our PPAs generally provide for the payment of 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. We expect that our Product Segment revenues will remain robust until the end of 2013 as a result of new orders and current backlog.

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

	Revenues (dollars in thousands)				% of Revenues for Period Indicated			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30, 2013		September 30,		September 30, 2013		September 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
Revenues:								
Electricity	$88,994	$77,612	$245,005	$238,837	68.1 %	58.7 %	60.9 %	61.5 %
Product	41,755	54,685	157,329	149,616	31.9	41.3	39.1	38.5
Total	$130,749	$132,297	$402,334	$388,453	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 (dollars in thousands)				% of Revenues for Period Indicated			
	Three Months		Nine Months		Three Months		Nine Months	
	Ended September 30,		Ended September 30,		Ended September 30,		Ended September 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
Electricity Segment:								
United States	$66,073	$59,179	$184,777	$185,910	74.2 %	76.2 %	75.4 %	77.8 %
Foreign	22,921	18,433	60,228	52,927	25.8	23.8	24.6	22.2
Total	$88,994	$77,612	$245,005	$238,837	100.0%	100.0%	100.0%	100.0%
Product Segment:								
United States	$13,832	$11,417	$43,696	$11,417	33.1 %	20.9 %	27.8 %	7.6 %
Foreign	27,943	43,268	113,633	138,199	66.9	79.1	72.2	92.4
Total	$41,755	$54,685	$157,329	$149,616	100.0%	100.0%	100.0%	100.0%

For the nine months ended September 30, 2013, 72.2% of our revenues attributable to our Product Segment were generated outside of the United States.

Seasonality

In the Electricity Segment we have identified that 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, and as a result have a favorable impact on 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 (such as depreciation and amortization) 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. 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 4.1% and 4.3% of Electricity Segment revenues for the nine months ended September 30, 2013 and 2012, 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, Cash Equivalents, Marketable Securities and Short-Term Bank Deposit

Our cash, cash equivalents, marketable securities and a short-term bank deposit as of September 30, 2013 decreased to $35.4 million from $69.6 million as of December 31, 2012. This decrease was principally due to: (i) our use of $144.6 million to fund capital expenditures; (ii) a net change in restricted cash, cash equivalents and marketable securities of $7.7 million; (iii) repayment of $37.5 million of long-term debt; (iv) $10.2 million of cash paid to the Class B membership units of OPC (see “OPC Transaction” below); and (v) $11.9 million of cash used to repurchase Ormat Funding LLC (OFC) Senior Secured Notes. This decrease was partially offset by: (i) additional $45.0 million of net proceeds from the disbursement from Tranche II of the OPIC Loan, as described below under “Non-Recourse and Limited-Recourse Third-Party Debt”; (ii) $32.2 million derived from operating activities during the nine months ended September 30, 2013; (iii) $31.4 million of net proceeds from the ORTP Transaction (see “ORTP Transaction” below); (iv) net proceeds of $49.7 million from borrowers under our revolving credit lines with commercial banks; (v) a 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 (vi) net proceeds of $7.7 million from the sale of our interest in the Momotombo power plant. Our corporate borrowing capacity under committed lines of credit with different commercial banks as of September 30, 2013 was $479.6 million, as described below in “Liquidity and Capital Resources”, of which we have utilized $334.4 million (including $207.4 million of letters of credit) as of September 30, 2013.

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, 2012.

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,	
	2013	2012	2013	2012
	(Dollars in thousands, except per share data)		(Dollars in thousands, except per share data)	
Statements of Operations Historical Data:				
Revenues:				
Electricity	$88,994	$77,612	$245,005	$238,837
Product	41,755	54,685	157,329	149,616
	130,749	132,297	402,334	388,453
Cost of revenues:				
Electricity	61,356	59,924	175,085	172,785
Product	29,637	42,130	110,335	108,575
	90,993	102,054	285,420	281,360
Gross margin:				
Electricity	27,638	17,688	69,920	66,052
Product	12,118	12,555	46,994	41,041
	39,756	30,243	116,914	107,093
Operating expenses:				
Research and development expenses	838	1,436	3,446	3,948
Selling and marketing expenses	2,575	3,346	17,861	12,752
General and administrative expenses	6,546	6,132	20,264	20,163
Impairment charge	—	7,264	—	7,264
Write-off of unsuccessful exploration activities	—	—	—	1,919
Operating income	29,797	12,065	75,343	61,047
Other income (expense):				
Interest income	742	280	870	1,004
Interest expense, net	(18,459)	(15,400)	(51,826)	(44,541)
Foreign currency translation and transaction gains (losses)	1,258	615	3,844	(1,127)
Income attributable to sale of tax benefits	5,027	2,311	14,342	7,417
Other non-operating income, net	137	215	1,583	344
Income before income taxes and equity in losses of investees	18,502	86	44,156	24,144
Income tax provision	(5,201)	(1,088)	(15,028)	(10,148)
Equity in losses of investees	(158)	(1,245)	(149)	(1,542)

Income (loss) from continuing operations	13,143	(2,247)	28,979	12,454
Discontinued operations:				
Income from discountinued opearations (including gain on disposal of $0, $0, $3,646 and $0, respectively)	—	2,123	5,311	4,875
Income tax provision	—	(391)	(614)	(1,097)
Total income from discontinued operations	—	1,732	4,697	3,778
Net income (loss)	13,143	(515)	33,676	16,232
Net income attributable to noncontrolling interest	(193)	(67)	(600)	(278)
Net income (loss) attributable to the Company's stockholders	$12,950	$(582)	$33,076	$15,954
Earnings (loss) per share attributable to the Company's stockholders:				
Basic:				
Income (loss) from continuing operations	$0.29	$(0.05)	$0.62	$0.27

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Discontinued operations	—	0.04	0.10	0.08
Net income (loss)	$0.29	$(0.01)	$0.72	$0.35
Diluted:				
Income (loss) from continuing operations	$0.28	$(0.05)	$0.62	$0.27
Discontinued operations	—	0.04	0.10	0.08
Net income (loss)	$0.28	$(0.01)	$0.72	$0.35
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:				
Basic	45,438	45,431	45,433	45,431
Diluted	45,494	45,431	45,454	45,438

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2013	**2012**	**2013**	**2012**
Statements of Operations Percentage Data:				
Revenues:				
Electricity	68.1 %	58.7 %	60.9 %	61.5 %
Product	31.9	41.3	39.1	38.5
	100.0	100.0	100.0	100.0
Cost of revenues:				
Electricity	68.9	77.2	71.5	72.3
Product	71.0	77.0	70.1	72.6
	69.6	77.1	70.9	72.4
Gross margin:				
Electricity	31.1	22.8	28.5	27.7
Product	29.0	23.0	29.9	27.4
	30.4	22.9	29.1	27.6
Operating expenses:				
Research and development expenses	0.6	1.1	0.9	1.0
Selling and marketing expenses	2.0	2.5	4.4	3.3
General and administrative expenses	5.0	4.6	5.0	5.2
Impairment charge	0.0	5.5	0.0	1.9
Write-off of unsuccessful exploration activities	0.0	0.0	0.0	0.5
Operating income	22.8	9.1	18.7	15.7
Other income (expense):				
Interest income	0.6	0.2	0.2	0.3
Interest expense, net	(14.1)	(11.6)	(12.9)	(11.5)
Foreign currency translation and transaction gains (losses)	1.0	0.5	1.0	(0.3)
Income attributable to sale of tax benefits	3.8	1.7	3.6	1.9
Other non-operating income, net	0.1	0.2	0.4	0.1
Income before income taxes and equity in losses of investees	14.2	0.1	11.0	6.2
Income tax provision	(4.0)	(0.8)	(3.7)	(2.6)

Equity in losses of investees	(0.1)	(0.9)	(0.0)	(0.4)
Income (loss) from continuing operations	10.1	(1.7)	7.2	3.2
Discontinued operations:				
Income from discountinued operations (including gain on disposal of $0, $0, $3,646 and $0, respectively)	0.0	1.6	1.3	0.8
Income tax provision	0.0	(0.3)	(0.2)	0.0
Total income from discontinued operations	0.0	1.4	1.2	0.8
Net income (loss)	10.1	(0.4)	8.4	4.2
Net income attributable to noncontrolling interest	(0.1)	(0.1)	(0.1)	(0.1)
Net income (loss) attributable to the Company's stockholders	9.9 %	(0.4)%	8.2 %	4.1 %

Comparison of the Three Months Ended September 30, 2013 and the Three Months Ended September 30, 2012

Total Revenues

Total revenues for the three months ended September 30, 2013 were $130.7 million, compared to $132.3 million for the three months ended September 30, 2012, which represented a 1.2% decrease. This decrease was attributable to our Product Segment, in which revenues decreased by 23.6% compared to the corresponding period in 2012. The decrease was partially offset by an increase of 14.7% in revenues from our Electricity Segment over the corresponding period in 2012.

Electricity Segment

Revenues attributable to our Electricity Segment for the three months ended September 30, 2013 were $89.0 million, compared to $77.6 million for the three months ended September 30, 2012, which represented a 14.7% increase in such revenues. This increase was primarily due to (i) a $6.4 million increase in revenues from our Plant 2 in the Olkaria III complex, which commenced commercial operation at the beginning of May 2013 and (ii) a net loss of $0.3 million on derivative contracts on oil and natural gas prices, compared to $3.7 million, over the corresponding period in 2012. This increase was partially offset by a $1.7 million decrease, resulting from lower generation and lower energy rates in the Amatitlan power plant**.** Lower generation in the Amatitlan resulted from a mechanical failure we had in one of the wells. Drilling of a new well was completed and will be connected to the power plant during the fourth quarter. Power generation in our power plants increased by 5.0% from 938,162 MWh in the three months ended September 30, 2012 to 985,531 MWh in the three months ended September 30, 2013 mainly due to the commercial operation of Plant 2 in the Olkaria III complex.

Product Segment

Revenues attributable to our Product Segment for the three months ended September 30, 2013 were $41.8 million, compared to $54.7 million for the three months ended September 30, 2012, which represented a 23.6% decrease. The decrease in our Product Segment revenues was primarily due to the completion of the Ngatamariki project in New Zealand during June 2013, as the majority of the Product Segment revenues in the three months ended September 30, 2012 were from the Ngatamariki project compared to nil in the three months ended September 30, 2013. The decrease was partially offset due to progress in a number of contracts this quarter.

Total Cost of Revenues

Total cost of revenues for the three months ended September 30, 2013 was $91.0 million, or 69.6% of total revenues, compared to $102.1 million for the three months ended September 30, 2012, or 77.1% of total revenues, which represented a 10.8% decrease. This decrease was primarily due to the decrease in cost of revenues from our Product Segment.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the three months ended September 30, 2013 was $61.4 million, or 68.9% of electricity revenues, compared to $59.9 million, or 77.2% of electricity revenues, for the three months ended September 30, 2012. The decrease in the cost of revenues as percentage of revenue was mainly attributable to the decrease in depreciation in our North Brawley power plant as a result of the impairment recorded in the fourth quarter of 2012 and in our Mammoth complex, due to fully depreciating a portion of its equipment since the prior period. This decrease was partially offset due to additional cost of revenues from our Plant 2 in the Olkaria III complex, which commenced commercial operation at the beginning of May 2013.

Product Segment

Total cost of revenues attributable to our Product Segment for the three months ended September 30, 2013 was $29.6 million, or 71.0% of Product Segment revenues, compared to $42.1 million, or 77.0% of Product Segment revenues, for the three months ended September 30, 2012, which represented a 29.7% decrease. This decrease was primarily due to cost of revenues in the three months ended September 30, 2012 from the Ngatamariki project compared to nil in the three months ended September 30, 2013, as the project was successfully completed during the six months ended June 30, 2013, as discussed above. The decrease was partially offset by the cost related to the progress we made in a number of contracts, as discussed above. The decrease as a percentage of revenues was mainly attributable to the different margins in the various sales contracts.

Research and Development Expenses

Research and development expenses for the three months ended September 30, 2013 were $0.8 million, compared to $1.4 million for the three months ended September 30, 2012. The research and development expenses are net of grants from the U.S. Department of Energy in the amount of $0.2 million and $0.1 million for the three months ended September 30, 2013 and 2012, respectively, related to the Enhanced Geothermal System project.

Selling and Marketing Expenses

Selling and marketing expenses for the three months ended September 30, 2013 were $2.6 million, compared to $3.3 million for the three months ended September 30, 2012. The decrease was mainly due to lower commission costs. Selling and marketing expenses for the three months ended September 30, 2013 constituted 2.0% of total revenues for such period, compared to 2.5% for the three months ended September 30, 2012.

General and Administrative Expenses

General and administrative expenses for the three months ended September 30, 2013 were $6.5 million, compared to $6.1 million for the three months ended September 30, 2012, which represented a 6.8% increase. General and administrative expenses for the three months ended September 30, 2013 constituted 5.0% of total revenues for such period, compared to 4.6% for the three months ended September 30, 2012.

Impairment Charge

There was no impairment charge for the three months ended September 30, 2013. During the three months ended September 30, 2012, OREG 4 power plant, which generates electricity using recovered heat and had a carrying value of $10.9 million, was tested for recoverability due to continued low output and was written down to its fair value of $3.6 million. The impairment loss of $7.3 million is presented in our condensed consolidated statements of operations and comprehensive income (loss) under “Impairment charge”.

We evaluate long-lived assets, including power plants, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Such evaluations include estimates of future cash flows. If actual cash flows differ significantly from our current estimates, a material impairment charge may be required in the future.

Operating Income

Operating income for the three months ended September 30, 2013 was $29.8 million, compared to $12.1 million for the three months ended September 30, 2012. The increase in operating income was principally attributable to: (i) the increase in our gross margin in our Electricity Segment which resulted primarily from the increase in our electricity revenues discussed above; and (ii) an impairment charge of $7.3 million recorded in the three months ended September 30, 2012, as discussed above. Operating income attributable to our Electricity Segment for the three months ended September 30, 2013 was $20.7 million, compared to $4.7 million for the three months ended September 30, 2012. Operating income attributable to our Product Segment for the three months ended September 30, 2013 was $9.1 million, compared to $7.4 million for the three months ended September 30, 2012.

Interest Expense, Net

Interest expense, net for the three months ended September 30, 2013 was $18.5 million, compared to $15.4 million for the three months ended September 30, 2012. This increase was primarily due to an increase of $1.9 million in interest expense related to the sale of tax benefits, and a $0.7 million decrease related to interest capitalized to projects.

Foreign Currency Translation and Transaction Gains

Foreign currency translation and transaction gains for the three months ended September 30, 2013 were $1.3 million, compared to $0.6 million for the three months ended September 30, 2012.

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, 2013 was \$5.0 million, compared to \$2.3 million for the three months ended September 30, 2012. 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 \$1.1 million and \$3.9 million, respectively, in the three months ended September 30, 2013, compared to PTCs and taxable income or loss generated by OPC and allocated to the investors in the three months ended September 30, 2012.

Income Taxes

Income tax provision for the three months ended September 30, 2013 was \$5.2 million, compared to \$1.1 million for the three months ended September 30, 2012. Our effective tax rate for the three months ended September 30, 2013 and 2012 was 28.1% and 1,265.1%, respectively. The effective tax rate differs from the statutory rate of 35% for the three months ended September 30, 2013, primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions.

Income (Loss) from Continuing Operations

Income from continuing operations for the three months ended September 30, 2013 was \$13.1 million, compared to a loss of \$2.2 million for the three months ended September 30, 2012. The increase in income from continuing operations of \$15.3 million was principally attributable to (i) a \$17.7 million increase in operating income and (ii) a \$2.7 million increase in income attributable to sale of tax benefits. This increase was offset partially by a \$3.1 million increase in interest expense, net, and \$4.1 million increase in income tax provision.

Discontinued Operations

In June 2013, Ormat Holding Corp. sold its stake 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 three months ended June 30, 2013. The operations of the MPC for the three months ended September 30, 2012, have been included in discontinued operations. Discontinued operations for the three months ended September 30, 2012 include revenues of \$3.8 million of MPC.

Net Income (Loss)

Net income for the three months ended September 30, 2013 was $13.1 million, compared to a net loss of $0.5 million for the three months ended September 30, 2012, which represents an increase of $13.6 million. The increase was principally attributable to the increase in income from continuing operations in the amount of $15.3 million, as discussed above.

Comparison of the Nine Months Ended September 30, 2013 and the Nine Months Ended September 30, 2012

Total Revenues

Total revenues for the nine months ended September 30, 2013 were $402.3 million, compared to $388.5 million for the nine months ended September 30, 2012, which represented a 3.6% increase in total revenues. This increase was attributable to both our Product and Electricity Segments, in which revenues increased by 5.1% and 2.6%, respectively, over the corresponding period in 2012.

Electricity Segment

Revenues attributable to our Electricity Segment for the nine months ended September 30, 2013 were $245.0 million, compared to $238.8 million for the nine months ended September 30, 2012, which represented a 2.6% increase. This increase was primarily due to a $27.6 million increase in revenues from our Olkaria III Plant 2, which commenced commercial operation at the beginning of May 2013, our McGinness Hills power plant, which commenced commercial operation in July 2012, and our Tuscarora power plant which started to receive commercial rates in the second quarter of 2012. This increase was partially offset by: (i) a $11.0 million decrease resulting from the impact of low natural gas prices on the energy rates in our SO#4 PPAs in California, which at the beginning of May 2012 changed from a fixed rate to a variable rate that is subject mainly to the fluctuations in natural gas prices; (ii) a $9.0 million net decrease due to reduced generation in some of our power plants and a reduction in energy rates in our Puna and Amatitlan power plants and (iii) a net loss of $1.5 million on derivative contracts on oil and natural gas prices, compared to a net gain of $0.1 million, over the corresponding period in 2012. Power generation in our power plants increased by 7.5% from 2,876,158 MWh in the nine months ended September 30, 2012 to 3,092,482 MWh in the nine months ended September 30, 2013.

Product Segment

Revenues attributable to our Product Segment for the nine months ended September 30, 2013 were $157.3 million, compared to $149.6 million for the nine months ended September 30, 2012, which represented a 5.2% increase. The increase in our Product Segment revenues reflects the increase in new customer orders that we secured in 2012 and 2013. The increase was partially offset due to revenue in the nine months ended September 30, 2012 from the Ngatamariki project in New Zealand, compared to the nine months ended September 30, 2013.

Total Cost of Revenues

Total cost of revenues for the nine months ended September 30, 2013 was $285.4 million, compared to $281.4 million for the nine months ended September 30, 2012, which represented a 1.4% increase. This slight increase was primarily due to the increase in cost of revenues from both our Electricity and Product Segments. As a percentage of total revenues, our total cost of revenues for the nine months ended September 30, 2013 was 70.9%, compared to 72.4% for the nine months ended September 30, 2012. The decrease was attributable to both our Electricity and Product Segments.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the nine months ended September 30, 2013 was $175.1 million, compared to $172.8 million for the nine months ended September 30, 2012, which represented a 1.3% increase. This increase was primarily due to additional cost of revenues from our new plants, the Olkaria III Plant 2, which commenced commercial operation at the beginning of May 2013 and McGinness Hills power plant, which commenced commercial operations in July 2012. The increase was primarily offset by a decrease in depreciation in (i) our North Brawley power plant as a result of impairment recorded in the fourth quarter of 2012 and (ii) our Mammoth complex, due to fully depreciating a portion of its equipment in previous quarters as a result of the planned repowering and purchase of new equipment. As a percentage of total revenues, the total cost of revenues attributable to our Electricity Segment for the nine months ended September 30, 2013 was 71.5%, compared to 72.3% for the nine months ended September 30, 2012. This decrease was attributable to the increase in electricity revenues as discussed above.

Product Segment

Total cost of revenues attributable to our Product Segment for the nine months ended September 30, 2013 was $110.3 million, compared to $108.6 million for the nine months ended September 30, 2012, which represented a 1.6% increase. As discussed above, this increase was primarily due to the increase in revenues from our Product Segment.

As discussed above, the increase was partially offset by the higher cost of revenues from the Ngatamariki project in the nine months ended September 30, 2012, which we completed in June 2013, compared to the nine months ended September 30, 2013. 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, 2013 was 70.1%, compared to 72.6% for the nine months ended September 30, 2012. The decrease was mainly attributable to the different margins in the various sales contracts.

Research and Development Expenses

Research and development expenses for the nine months ended September 30, 2013 were $3.4 million, compared to $3.9 million for the nine months ended September 30, 2012. The research and development expenses are net of grants from the U.S. Department of Energy in the amount of $1.3 million and $0.3 million for the nine months ended September 30, 2013 and 2012, respectively, related to the Enhanced Geothermal Systems project.

Selling and Marketing Expenses

Selling and marketing expenses for the nine months ended September 30, 2013 were $17.9 million, compared to $12.8 million for the nine months ended September 30, 2012. The increase was primarily due to a one-time early termination fee in the amount of $9.0 million we paid to SCE relating to the termination of the G1 and G3 PPAs for the Mammoth complex, as described above. Excluding the one-time termination fee, selling and marketing expenses for the nine months ended September 30, 2013 constituted 2.2% of total revenues for such period, compared to 3.3% for the nine months ended September 30, 2012.

General and Administrative Expenses

General and administrative expenses for the nine months ended September 30, 2013 were $20.3 million, compared to $20.2 million for the nine months ended September 30, 2012, which represented a 0.5% increase. General and administrative expenses for the nine months ended September 30, 2013 constituted 5.0% of total revenues, compared to 5.2% for the nine months ended September 30, 2012.

Impairment Charge

There was no impairment charge for the nine months ended September 30, 2013. During the nine months ended September 30, 2012, the OREG 4 power plant, which generates electricity using recovered heat and had a carrying value of $10.9 million, was tested for recoverability due to continued low output and was written down to its fair value of $3.6 million. The impairment loss of $7.3 million is presented in our condensed consolidated statements of operations and comprehensive income (loss) under “Impairment charge”.

Write-off of Unsuccessful Exploration Activities

There were no write-offs of unsuccessful exploration activities for the nine months ended September 30, 2013. Write-off of unsuccessful exploration activities for the nine months ended September 30, 2012 was $1.9 million. This represented the write-off of exploration costs related to several projects in Nevada, which we determined would not support commercial operations.

Operating Income

Operating income for the nine months ended September 30, 2013 was $75.3 million, compared to $61.0 million for the nine months ended September 30, 2012. The increase in operating income was principally attributable to (i) the increase in both our electricity and product gross margins, which was primarily associated with the increase in both electricity and product revenues as discussed above, and (ii) an impairment charge of $7.3 million in the nine months ended September 30, 2012, as discussed above. The increase was partially offset due to the one-time early termination fee of $9.0 million included in selling and marketing expenses discussed above. Operating income attributable to our Electricity Segment for the nine months ended September 30, 2013 was $42.1 million, compared to $36.0 million for the nine months ended September 30, 2012. Operating income attributable to our Product Segment for the nine months ended September 30, 2013 was $33.3 million, compared to $25.1 million for the nine months ended September 30, 2012.

Interest Expense, Net

Interest expense, net for the nine months ended September 30, 2013 was $51.8 million, compared to $44.5 million for the nine months ended September 30, 2012, which represented a 16.4% increase. This increase was primarily due to an increase of $4.2 million in interest expense related to the sale of tax benefits, and a $3.3 million decrease related to interest capitalized to project.

Foreign Currency Translation and Transaction Gains (Losses)

Foreign currency translation and transaction used to cover our foreign exchange exposure, resulted in gains for the nine months ended September 30, 2013 of $3.8 million, compared to losses of $1.1 million for the nine months ended September 30, 2012. The increase was primarily due to gains on foreign currency forward contracts for the nine months ended September 30, 2013, 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" below) for the nine months ended September 30, 2013 was $14.3 million, compared to $7.4 million for the nine months ended September 30, 2012. 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 $4.0 million and $10.3 million, respectively, in the nine months ended September 30, 2013, compared to PTCs and taxable income or loss generated by OPC and allocated to the investors in the nine months ended September 30, 2012.

Income Taxes

Income tax provision for the nine months ended September 30, 2013 was $15.0 million, compared to $10.1 million for the nine months ended September 30, 2012. Our effective tax rate for the nine months ended September 30, 2013 and 2012, was 34.0% and 42.0%, respectively. The effective tax rate differs from the federal statutory rate of 35% for the nine months ended September 30, 2013, primarily due to unbenefited losses in the U.S. and certain foreign jurisdictions.

Income from Continuing Operations

Income from continuing operations for the nine months ended September 30, 2013 was $29.0 million, compared to $12.5 million for the nine months ended September 30, 2012. The increase in income from continuing operations of $16.5 million was principally attributable to (i) a $6.9 million increase in income attributable to sale if tax benefits and (ii) a $4.9 million increase in foreign currency translation and transaction gains which was partially offset by a $7.3 million increase in interest expense, net, and $4.9 million increase in income tax provision.

Discontinued Operations

In June 2013, Ormat Holding Corp. sold its stake 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 and 2012, have been included in discontinued operations. Discontinued operations for the nine months ended September 30, 2013 and 2012 include revenues of $4.9 million and $9.9 million, respectively of the MPC.

Net Income

Net income for the nine months ended September 30, 2013 was $33.7 million, compared to $16.2 million for the nine months ended September 30, 2012, which represents an increase of $17.5 million. The increase in net income was principally attributable to the increase in income from continuing operations in the amount of $16.5 million and from an after-tax gain on sale of $3.6 million resulted from the sale of the MPC, each 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 including the issuance by OFC 2 LLC (OFC 2) of its Senior Secured Notes, project financing (including the OPIC loan, OPC and ORTP Transactions described below), and cash grants we received under the ARRA. We have utilized this cash to develop and construct power generation plants, to fund our acquisitions, and to meet our other cash and liquidity needs.

We believe that based on our plans to increase the 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.

As of September 30, 2013, we had access to (i) $35.4 million in cash, cash equivalents and (ii) $145.2 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks (including loans and letters of credit).

Our estimated capital needs for the remainder of 2013 include approximately $59.0 million for capital expenditures on new projects under development or construction, exploration activity, operating projects, and machinery and equipment, as well as $30.9 million for debt repayment.

We expect to finance these requirements with: (i) the sources of liquidity described above; (ii) positive cash flows from our operations; (iii) future project financing and refinancing (including construction loans); and (iv) cash grants available to us under the ARRA in respect of new projects that will be placed in service before the end of 2013. Management believes that these sources will be sufficient to 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 believe that the transition to variable energy prices under the Ormesa and Mammoth PPAs and the impact of the currently low natural gas prices on the revenues under these PPAs may cause OFC to not meet the DSCR ratio requirements for making distributions, but we do not believe that there will be an event of default by OFC. We are only required to measure these covenants on a semi-annual basis and as of June 30, 2013, the last measurement date of the covenants, the actual historical 12-months DSCR was 1.25. There were $96.2 million and $114.1 million of OFC Senior Secured Notes outstanding as of September 30, 2013 and December 31, 2012, respectively.

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 first nine months of 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. The Company is only required to measure these covenants on a semi-annual basis and as of June 30, 2013, the last measurement date of the covenants, the actual historical 12-months DSCR was 1.26. There were $74.0 million and $76.5 million of OrCal Senior Secured Notes outstanding as of September 30, 2013 and December 31, 2012, 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.

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 will guarantee 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 December 31, 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.

Issuance of the Series B Notes is dependent on the Jersey Valley power plant reaching certain operational targets in addition to the other conditions precedent noted above. If issued, the aggregate principal amount of the Series B Notes will not exceed $28.0 million, and such proceeds would be used to finance a portion of the construction costs of Phase I of the Jersey Valley power plant.

The OFC 2 Issuers have sole discretion regarding whether to commence construction of Phase II of any of the Jersey Valley, McGinness Hills and Tuscarora power plants. If Phase II construction is undertaken for any of the power plants, the OFC 2 Issuers may issue Phase II tranches of Notes, comprised of one or more of Series C Notes, Series D Notes, Series E Notes and Series F Notes, to finance a portion of the construction costs of such Phase II of any facility. The aggregate principal amount of all Phase II Notes may not exceed $170.0 million. The aggregate principal amount of each series of Notes comprising a Phase II tranche will be determined by the OFC 2 Issuers in their sole discretion provided that certain financial ratios are satisfied pursuant to the terms of the Note Purchase Agreement and subject to the aggregate limit noted above.

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, 2013, the last measurement date of the covenants, the historical actual DSCR was 2.20 and the pro-forma 12-month DSCR was 1.90. As of September 30, 2013, there were $146.6 million of OFC 2 Senior Secured Notes outstanding.

We provided a guarantee in connection with the issuance of the Series A Notes, and will provide a guarantee in connection with the issuance of each other Series of OFC 2 Senior Secured Notes, which will be available to be drawn upon if certain trigger events occur. 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 wholly-owned subsidiaries, entered into a finance agreement with OPIC 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 in November 2012.

The OPIC Loan is comprised of up to 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 up to $180.0 million will be used to fund the construction and well field drilling for the expansion of the Olkaria III geothermal power complex (Plant 2). 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 is a stand-by tranche in an aggregate principal amount of up to $45.0 million, and will be made available to OrPower 4 for the construction of Plant 3 of Olkaria III complex. The final documentation of the Tranche III of the OPIC Loan is currently being negotiated by OPIC and OrPower 4.

On July 15, 2013 we completed the conversion of the interest rate applicable to both Tranche I and Tranche II from a floating interest rate to into a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance of $81.5 million and matures on December 15, 2030 and Tranche II, which has an outstanding balance of $177.4 million and matures on June 15, 2030, is 6.31%.

The applicable tranche interest rate will be determined at the time of the actual disbursement of loan proceeds based upon, and in connection with the issuance of certificates of participation in the OPIC Loan. The payment of principal and interest on the certificates of participation is fully guaranteed by OPIC, and is backed by the full faith and credit of the U.S. government.

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 $43.4 million as of September 30, 2013, 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.

As of September 30, 2013, $258.8 million of the OPIC Loan was outstanding.

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 TCW Global Project Fund II, Ltd. (TCW). The loan bears interest at a rate of 9.83%, will mature on June 15, 2016, and is payable in quarterly installments. There are various restrictive covenants under the loan, which include (i) a projected 12-month DSCR of not less than 1.2 and (ii) a long-term debt to equity ratio not to exceed 4.0 (both of which are measured quarterly). If Ortitlan fails to comply with these financial ratios it will be prohibited from making distributions to its shareholders. In addition, subject to certain cure rights, such failure will constitute an event of default. As of September 30, 2013, the projected 12-month DSCR was 1.60 and the debt to equity ratio was 2.08, and $32.2 million of this loan was outstanding.

Full-Recourse Third-Party Debt

Union Bank. In February 2012, Ormat Nevada entered into an amended and restated credit agreement with Union Bank. Under the amended and restated agreement, the credit termination date was extended from February 15, 2012 to February 7, 2014 and the aggregate amount available under the credit agreement was increased from $39.0 million to $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, 2013: (i) the actual 12-month debt to EBITDA ratio was 2.60; (ii) the 12-month DSCR was 2.73; and (iii) the distribution leverage ratio was 1.64. 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, 2013, letters of credit in the aggregate amount of $41.7 million remain issued and outstanding under this credit agreement.

HSBC. In May 2013, Ormat Nevada, a wholly owned subsidiary of the Company, entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals. 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 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, 2013: (i) the actual 12-month debt to EBITDA ratio was 2.60; (ii) the 12-month DSCR was 2.73; and (iii) the distribution leverage ratio was 1.64. 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, 2013, letters of credit in the aggregate amount of $10.2 million remain issued and outstanding under this credit agreement.

Credit Agreements. We also have credit agreements with five other commercial banks for an aggregate amount of $404.6 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 $260.0 million and (ii) the issuance of one or more letters of credit in the amount of up to $144.6 million. The credit agreements mature between February 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, 2013, loans in the total amount of $123.3 million were outstanding, and letters of credit with an aggregate stated amount of $155.5 million were issued and outstanding under these credit agreements. The $123.3 million in loans are for terms of three months or less and bear interest at a weighted average rate of 2.35%.

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, 2013, $7.5 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, 2013, $13.3 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, 2013, $14.0 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, 2013, $15.0 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, $43.4 million is outstanding under the DEG Loan (out of which $29.8 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"). The amended and restated DEG Loan Agreement provides for: (i) the prepayment in full of two loans thereunder in the total principal amount of approximately $20.5 million; (ii) 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; (iii) the establishment of a LIBOR floor of 1.25% in respect of one of the loans under the DEG Loan Agreement and (iv) 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 million and in no event less than 30% of total assets; (ii) 12-month debt, net of cash, cash equivalents, marketable securities and short-term bank deposits to 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, 2013: (i) total equity was $737.0 million and the actual equity to total assets ratio was 33.99% and (ii) the 12-month debt, net of cash, cash equivalents, marketable securities and short-term bank deposits to EBITDA ratio was 5.92. 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, 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, 2013, letters of credit in the aggregate amount of $245.1 million remained issued and outstanding, out of which $207.4 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" and $37.7 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. In October, 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 in February, 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. Pursuant to the term of the agreement, JPM paid approximately $35.7 million to Ormat Nevada and undertook to make additional payments to ORTP 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 approximately $8.7 million.

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 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.

For the three months and nine months ended September 30, 2013, the impact of the ORTP transaction was a net gain of $2.0 million and $6.1 million, respectively, on our condensed consolidated statements of operations and comprehensive income (loss). For the three months and nine months ended September 30, 2013, revenues of $3.9 million and $10.3 million, respectively, were recognized in income attributable to the sale of tax benefits and a $1.9 million and $4.2 million finance charge was recognized in interest expense, respectively.

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 $8.9 million as of September 30, 2013. 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, 2013:

Date Declared	**Dividend Amount** per Share	**Record Date**	**Payment Date**
May 8, 2012	$ 0.04	May 21, 2012	May 30, 2012
August 1, 2012	$ 0.04	August 14, 2012	August 23, 2012
August 6, 2013	$ 0.04	August 19, 2013	August 29, 2013
November 6, 2013	$ 0.04	November 20, 2013	December 4, 2013

Historical Cash Flows

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

	Nine Months Ended September 30,	
	2013	**2012**
	(Dollars in thousands)	

Net cash provided by operating activities	$32,226	$62,384
Net cash used in investing activities	(128,198)	(53,611)
Net cash provided by (used in) financing activities	64,779	(71,135)
Net change in cash and cash equivalents	(31,193)	(62,362)

For the Nine Months Ended September 30, 2013

Net cash provided by operating activities for the nine months ended September 30, 2013 was $32.2 million, compared to $62.4 million for the nine months ended September 30, 2012. The net decrease of $30.2 million resulted primarily from (i) a decrease in billings in excess of costs and estimated earnings on uncompleted contracts, net of $39.3 million in our Product Segment in the nine months ended September 30, 2013, compared to $4.3 million in the nine months ended September 30, 2012, as a result of timing in billing of our customers; (ii) an increase in receivables of $23.2 million in the nine months ended September 30, 2013, compared to an increase of $29.7 million in the nine months ended September 30, 2012, as a result of timing of collection from our customers; and (iii) a decrease in accounts payable and accrued expenses of $21.4 million in the nine months ended September 30, 2013, compared to an increase of $9.5 million in the nine months ended September 30, 2012 as a result of timing of payments to our vendors. The decrease was partially offset due to (i) the increase in net income of $17.5 million, from a net income of $16.2 million for the nine months ended September 30, 2012 to $33.7 million for the nine months ended September 30, 2013 as described above; and (ii) an increase in deferred income tax provision of $14.2 million in the nine months ended September 30, 2013, compared to $5.9 million in the nine months ended September 30, 2012, as a result of the increase in income before income taxes.

Net cash used in investing activities for the nine months ended September 30, 2013 was $128.2 million, compared to $53.6 million for the nine months ended September 30, 2012. 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. The principal factors that affected our net cash used in investing activities during the nine months ended September 30, 2012 were capital expenditures of $186.3 million, primarily for our facilities under construction reduced by (i) cash grants in the amount of $119.2 million received from the U.S. Treasury under Section 1603 of the ARRA in the second and third quarters of 2012 relating to the enhancement of our Puna geothermal complex and to our Jersey Valley, Tuscarora and McGinness Hills geothermal power plants and (ii) a net decrease of $18.8 million in marketable securities.

Net cash provided by financing activities for the nine months ended September 30, 2013 was $64.8 million, compared to $71.1 million used in for the nine months ended September 30, 2012. The principal factors that affected the 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, reduced by: (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). The principal factors that affected our net cash used in financing activities during the nine months ended September 30, 2012 were: (i) a net decrease of $26.6 million against our revolving lines of credit with commercial banks; (ii) the repayment of long-term debt in the amount of $28.9 million; and (iii) cash paid to non-controlling interest in the amount of $11.0 million.

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, 2013 was $60.3 million, compared to $48.2 million for the three months ended September 30, 2012. Adjusted EBITDA for the nine months ended September 30, 2013 was $175.7 million, compared to $150.5 million for the nine months ended September 30, 2012.

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, 2013 and 2012:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2013	**2012**	**2013**	**2012**
	(Dollars in thousands)		**(Dollars in thousands)**	

Net cash provided by (used in) operating activities	$ 12,276	$ (9,695)	$ 32,226	$ 62,384
Adjusted for:				
Interest expense, net (excluding amortization of deferred financing costs)	17,405	14,202	47,367	40,931
Interest income	(742)	(280)	(870)	(1,004)
Income tax provision	5,201	1,479	15,642	11,245
Adjustments to reconcile net income or loss to net cash provided by operating activities (excluding depreciation and amortization)	26,115	35,236	72,361	29,661
EBITDA	$ 60,255	$ 40,942	$ 166,726	$ 143,217
Termination fee	—	—	8,979	—
Impairment charge	—	7,264	—	7,264
Adjusted EBITDA	$ 60,255	$ 48,206	$ 175,705	$ 150,481
Net cash provided by (used in) investing activities	$ (25,029)	$ 13,417	$ (128,198)	$ (53,611)
Net cash provided by (used in) financing activities	$ 19,295	$ (32,882)	$ 64,779	$ (71,135)

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:

Heber Solar PV Project. We are currently developing the 10 MW Heber Solar PV project located in Imperial County, California. We signed a 20-year PPA with the (IID). Installation of the solar modules was completed and testing has started. We expect to begin commercial operation by the end of 2013, subject to timely completion of the interconnection that is to be provided by IID.

Mammoth Complex. We are currently in the process of repowering the G1 plant at the Mammoth complex located in Mammoth Lakes, California, by replacing the old units of the G1 plant with new Ormat-manufactured equipment. We expect the replacement of the equipment to optimize the operation of the complex. We have completed manufacturing the new equipment for the plant and expect to complete the equipment replacement by the end of 2013.

Olkaria III Plant 3. Development of the 16 MW Plant 3 of the Olkaria III complex located in Naivasha, Kenya is in the final stages. We have completed the field development and started the construction on the site. We expect to commence commercial operation in the first half of 2014**.**

Don A. Campbell Project (formerly Wild Rose). We are currently developing the 16 MW Don Campbell project located in Mineral County, Nevada. Field development was completed and construction is in its final stage. We signed a 20-year PPA with the Southern California Power Public Authority at a rate of $99 per MWh. The new power plant is expected to come online by the end of 2013.

Heber 1Power Plant. We plan to enhance the Heber complex located in Imperial Valley, California, by adding new wells and replacing part of the old equipment with new equipment. We expect the enhancement to optimize the operation of the Heber complex. Completion is expected in the first half of 2014.

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 2013.

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 secured the required permits for continued drilling. 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 2013.

We have estimated approximately $214.0 million in capital expenditures for the projects listed above, of which we have invested approximately $140.0 million as of September 30, 2013. We expect to invest $36.0 million of such total in the remainder of 2013 and the remaining $38.0 million thereafter.

In addition, we estimate approximately $23.0 million in additional capital expenditures in the fourth quarter of 2013 to be allocated as follows: (i) $3.0 million in development of new projects; (ii) $7.0 million for maintenance capital expenditure; (iii) $12.0 million in exploration activities in various leases for geothermal resources in which we have started the exploration activity; and (iv) $1.0 million in enhancement of our production facilities. In the aggregate, we estimate our total capital expenditures for the remainder of 2013 will be approximately $59.0 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 May and July 2012, we entered into put transactions, and in October 2012, we entered into swap contracts to reduce our exposure to the price of natural gas, under these PPAs, until December 31, 2013. In September and October 2013, we entered into swap contracts to reduce our exposure to the price of natural gas, under these PPAs, until December 31, 2014. 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 April 2012, we entered into swap contracts, and in September 2012, we entered into put transactions to reduce our exposure to the price of oil, under the 25 MW PPA of the Puna complex, until December 31, 2013. In October 2013, we entered into swap contracts 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, 2013, 84.6% of our consolidated long-term debt bore a fixed rate and therefore was not subject to interest rate volatility risk. As of such date, 15.4% of our long-term debt was in the form of a floating rate instrument, exposing us to changes in interest rates in connection therewith, and $165.3 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 and our portfolio of marketable securities 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 primarily related to 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 prices, put options on natural gas prices, long-term debt obligations, and foreign currency exchange forward contracts. The swap contracts on oil prices, put options on 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, 2013 and December 31, 2012 by a hypothetical 10% and calculating the resulting change in the fair values.

The results of the sensitivity analysis calculations as of September 30, 2013 and December 31, 2012 are presented below:

Risk	Assuming a 10% Increase in Rates September 30, 2013	Assuming a 10% Increase in Rates December 31, 2012	Assuming a 10% Decrease in Rates September 30, 2013	Assuming a 10% Decrease in Rates December 31, 2012	Change in the Fair Value of
	(Dollars in thousands)				
NGI Price	$ (1,276)	$ (484)	$ 3,497	$ 6,097	NGI Swap
NYMEX Heating Oil Price	-	(439)	-	1,037	NYMEX HO2 Swap
ICE Brent Price	-	(122)	-	41	ICE Brent Swap
NYMEX Heating Oil Price	13	790	542	2,988	NYMEX HO2 Fixed Rate Put
ICE Brent Price	-	135	38	429	ICE Brent Fixed Rate Put
Foreign Currency	(5,414)	(5,074)	6,617	7,503	Foreign currency forward contracts
Interest Rate	(1,938)	(3,388)	1,962	3,557	OFC
Interest Rate	(1,389)	(1,550)	1,433	1,650	OrCal
Interest Rate	(5,619)	(5,600)	6,070	6,100	OFC 2
Interest Rate	(421)	(540)	432	560	Loan from DEG
Interest Rate	(10,186)	-	10,916	-	Loan from OPIC
Interest Rate	(377)	(532)	384	468	Loan from TCW
Interest Rate	(4,730)	(5,477)	4,836	5,623	Senior unsecured bonds
Interest Rate	-	(401)	-	99	Loan from institutional investors

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 15.3% and 14.5% of our total revenues for the three months ended September 30, 2013 and 2012, respectively, and 17.0% and 14.2% of our total revenues for the nine months ended September 30, 2013 and 2012, respectively.

Southern California Edison accounted for 20.9% and 20.4% of our total revenues for the three months ended September 30, 2013 and 2012, respectively, and 14.9% and 19.2% for the nine months ended September 30, 2013 and 2012, 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 8.7% and 8.4% of our total revenues for the three months ended September 30, 2013 and 2012, respectively, and 8.9% and 9.4% for the nine months ended September 30, 2013 and 2012, respectively.

KPLC accounted for 13.8% and 8.8% of our total revenues for the three months ended September 30, 2013 and 2012, respectively, and 10.9% and 8.0% for the nine months ended September 30, 2013 and 2012, respectively.

Government Grants and Tax Benefits

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. If we start 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 three months ended September 30, 2013 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 place 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 2014, and 12% in 2015 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.

In November 2012, new legislation amending the Investment Law was enacted. Under the new legislation, companies that have retained earnings as of December 31, 2011 from Benefited Enterprises may elect by November 11, 2013 to pay a reduced corporate tax rate set forth in the new legislation on such undistributed income and distribute a dividend from such income without being required to pay additional corporate tax with respect to such income. A company that makes this election will be required to make certain investments in its Benefited Enterprise by: (i) purchasing productive assets (other than buildings); (ii) investing in research and development in Israel; and/or (iii) paying salaries of new employees (other than directors and officers of the company) of the Benefited Enterprise. The number of new employees for these purposes will be determined in comparison to the number of employees employed by the Benefited Enterprise at the end of 2011. Such investment must be made over a period of five years commencing in the tax year in which the election is made. The amount of the required investment is determined pursuant to a formula set forth in the new legislation. A company that makes the election allowed under the new legislation cannot later undo its election. As of the date of this quarterly report Ormat Systems has not yet decided whether to make such election.

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, 2013, 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 2013 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***

On December 24, 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 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 I replacement project. The petition asks the court to set aside the approval of the CUP and adoption of the EIR and cause a new EIR to be prepared and circulated.

The Company believes that the petition is without merit and intends to respond and take necessary legal action to dismiss the proceedings. The Company responded to LiUNA's petition. Filing of the petition in and of itself does not have any immediate adverse implications for the Mammoth enhancement.

On January 4, 2012, the California Unions for Reliable Energy ("CURE") filed a petition in Alameda Superior Court, naming the California Energy Commission ("CEC") and the Company as defendant and real party in interest, respectively. The petition asked the court to order the CEC to vacate its decision which denied, with prejudice, the complaint filed by CURE against the Company with the CEC. The CURE complaint alleged that the Company's North Brawley Project and East Brawley Project both exceed the CEC's 50 MW jurisdictional threshold and therefore are subject to the CEC licensing authority rather than Imperial County licensing authority. In addition, the CURE petition asked the court to investigate and halt any ongoing violation of the Warren Alquist Act by the Company, and to award CURE attorney's fees and costs. As to North Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider provisions of the County permit for North Brawley, which CURE contends authorizes the Company to build a generating facility with a number of Ormat Energy Converters ("OECs") capable of generating more than 50 MW. As to East Brawley, CURE alleges that the CEC decision violated the Warren Alquist Act because it failed to consider the conditional use permit application for East Brawley, which CURE contends shows that the Company requested authorization to build a facility with a number of OECs capable of generating more than 50 MW.

The court held two hearings and on November 15, 2012 CURE's petition was denied. Any appeal of the court's decision had to be filed by March 4, 2013, and no appeal was filed.

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, 2012 filed with the SEC on March 11, 2013.

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 fiscal quarter of 2013.

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, 2013

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..

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.IN*	XBRL Instance Document.
101.SC*	XBRL Taxonomy Extension Schema Document.
101.CA*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DE*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LA*	XBRL Taxonomy Extension Label Linkbase Document.
101.PR*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not “filed” for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section and shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that the Company specifically incorporates such information by reference.