ORMAT TECHNOLOGIES, INC.
Form 10-K/A
June 19, 2018

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K/A

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

For the fiscal year ended December 31, 2017

Or

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

Commission file 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, including zip code)

Registrant's telephone number, including area code:

(775) 356-9029

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock $0.001 Par Value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K/A or any amendment to this Form 10-K/A.

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)	Emerging growth company

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

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

As of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $2,315,466,032 based on the closing price as reported on the New York Stock Exchange. Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date: As of February 23, 2018, the number of outstanding shares of common stock, par value $0.001 per share was 50,609,051.

Documents incorporated by reference: Part III (Items 10, 11, 12, 13 and 14) incorporates by reference portions of the Registrant's Proxy Statement for its Annual Meeting of Stockholders, which will be filed not later than 120 days after December 31, 2017.

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Certain Definitions

For convenience purposes in this filing on Form 10-K/A, all references to “Ormat”, “the Company”, “we”, “us”, “our compa “Ormat Technologies” or “our” refer to Ormat Technologies, Inc. and its consolidated subsidiaries.

Explanatory Note

This Amendment No. 1 to Form 10-K (this "Amendment") amends the Annual Report on Form 10-K for the year ended December 31, 2017 originally filed with the Securities and Exchange Commission (“SEC”) on March 16, 2018 (the "Original Filing") by Ormat Technologies, Inc. (the "Company").

Restatement

As further discussed in Note 1 to our consolidated financial statements in Part II, Item 8, "Financial Statements and Supplementary Data" of this 2017 Amendment, on May 16, 2018, we concluded that we would restate our previously issued consolidated financial statements as of and for the year ended December 31, 2017 to correct for (i) errors in our income tax provision, primarily related to the Company’s ability to utilize Federal tax credits in the United States ("U.S.") prior to their expiration starting in 2027, and the resulting impact on the Company’s deferred tax asset valuation allowance, and (ii) the inappropriate netting of certain deferred income tax assets and deferred income tax liabilities across different tax jurisdictions that was not permissible under U.S. generally accepted accounting principles. In addition, there were other immaterial prior period errors, including an out-of-period adjustment that had been previously recorded for the correction of an understated liability for unrecognized tax benefits related to intercompany interest. We also concluded that we would revise our previously issued consolidated financial statements as of and for the year ended December 31, 2016 and for the year ended December 31, 2015 to correct for errors in our income tax provision, primarily related to the translation of deferred tax liabilities in a foreign subsidiary. The restatements, for 2017, and revisions, for 2016 and 2015, is being effected through the Company’s filing of this Amendment. In connection with these restatements and revisions, the Company also recorded adjustments to correct other immaterial tax errors. This decision to restate and revise our previously issued financial statements was approved by, and with the continuing oversight of, the Company’s Board of Directors upon the recommendation of its Audit Committee.

These error corrections also resulted in the restatement, for 2017, and revision, for 2016, of the Company’s previously issued unaudited condensed consolidated financial statements for the three and six months ended June 30, 2017 and 2016, respectively, and the three and nine months ended September 30, 2017 and 2016, respectively, which restatements and revisions have been effected through the Company’s filing of an amendment on Form 10-Q/A for the quarter ended June 30, 2017 and an amendment on Form 10-Q/A for the quarter ended September 30, 2017. The revision of the Company's previously issued unaudited condensed consolidated financial statements for the quarter ended March 31, 2017 will be effected in connection with the Company's filing of its Form 10-Q for the quarter ended March 31, 2018. The impact of the restatement and revision of these unaudited periods, along with the restatement of the financial results for the quarter ended December 31, 2017 and the revision of the financial results for the quarter ended December 31, 2016, has been reflected within the unaudited quarterly financial information footnote in Part II, Item 8. "Financial Statements and Supplementary Data".

Internal Control Over Financial Reporting

Management, under the supervision and participation of our Chief Executive Officer and our Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017 using criteria established in *Internal Control — Integrated Framework (2013)* issued by the COSO and, based on this evaluation, concluded that our internal control over financial reporting was not effective as of December 31, 2017 as a result of the material weakness in our internal control over financial reporting. For a description of the material weakness in internal control over financial reporting and for an amended Management's Report on Internal Control over Financial Reporting, see Part II, Item 9A. "Controls and Procedures" of this Amendment.

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Amendment

The purpose of this Amendment is to (i) restate the Company's previously issued consolidated financial statements and related disclosures as of and for the year ended December 31, 2017, (ii) revise the Company's consolidated financial statements as of and for the year ended December 31, 2016 and for the year ended December 31, 2015, all contained in Part II, Item 8. "Financial Statements and Supplementary Data"; and (iii) revise the Selected Financial Data in Part II, Item 6. This Amendment also includes (a) in Part I, Item 1A: Risk Factors, revised disclosures relating to the material weakness and timeliness of periodic SEC filings, (b) in Part II, Item 8, restated unaudited quarterly financial data for each of the quarters ended June 30, September 30 and December 31, 2017 and revised unaudited quarterly financial data for each quarter in the year ended December 31, 2016 and for the quarter ended March 31, 2017, (c) in Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations," to reflect the correction of the errors described above and (d) an additional paragraph in Part II, Item 9A. "Controls and Procedures" including "Management's Report on Internal Control Over Financial Reporting" of the Original Filing to reflect the conclusions by the Company's management that the identified deficiency in the design of the Company's internal control over financial reporting related to its accounting for income taxes resulted in the errors described above. In addition, the Company has updated Note 24 to the consolidated financial statements contained in Part II, Item 8. "Financial Statements and Supplementary Data" to include disclosure of subsequent events occurring through the date of the filing of this Amendment.

Except as expressly set forth herein, this Amendment does not reflect events occurring after the date of the Original Filing or modify or update any of the other disclosures contained therein in any way other than as required to reflect the amendment discussed above. Accordingly, this Amendment should be read in conjunction with the Original Filing and our other filings with the SEC.

In addition, as required by Rule 12b-15 under the Securities Exchange Act of 1934, as amended, new certifications by our principal executive officer and principal financial officer are filed as exhibits to this Amendment.

Items Amended in this Filing

For reasons discussed above, we are filing this Amendment in order to amend the following items in our Original Report to the extent necessary to reflect the adjustments discussed above and make corresponding revisions to our financial data cited elsewhere in this Amendment:

Part I, Item 1A. Risk Factors
Part II, Item 6. Selected Financial Data
Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Part II, Item 8. Financial Statements and Supplementary Data
Part II, Item 9A. Controls and Procedures

In accordance with applicable SEC rules, this Amended Report includes new certifications required by Rule 13a-14 under the Securities Exchange Act of 1934 from our Chief Executive Officer and Chief Financial Officer dated as of the date of filing of this Amended Report.

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ORMAT TECHNOLOGIES, INC.

FORM 10-K/A FOR THE YEAR ENDED DECEMBER 31, 2017

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Glossary of Terms

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Definition
Amatitlan Loan	$42,000,000 in initial aggregate principal amount borrowed by our subsidiary Ortitlan Limitada from Banco Industrial S.A. and Westrust Bank (International) Limited.
AMM	Administrador del Mercado Mayorista (administrator of the wholesale market — Guatemala)
ARRA	American Recovery and Reinvestment Act of 2009
Auxiliary Power	The power needed to operate a geothermal power plant's auxiliary equipment such as pumps and cooling towers
Availability	The ratio of the time a power plant is ready to be in service, or is in service, to the total time interval under consideration, expressed as a percentage, independent of fuel supply (heat or geothermal) or transmission accessibility
Balance of Plant equipment	Power plant equipment other than the generating units including items such as transformers, valves, interconnection equipment, cooling towers for water cooled power plants, etc.
BESS	Battery Energy Storage Systems
BLM	Bureau of Land Management of the U.S. Department of the Interior
BOT	Build, operate and transfer
CAGR	Compound annual growth rate
Capacity	The maximum load that a power plant can carry under existing conditions, less auxiliary power
Capacity Factor	The ratio of the average load on a generating resource to its generating capacity during a specified period of time, expressed as a percentage
CARB	California Air Resources Board
CDC	Caisse des Dépôts et Consignations, a French state-owned financial organization
CFE	Comision Federal de Electricidad
C&I	Refers to the Commercial and Industrial sectors, excluding residential
CNE	National Energy Commission of Honduras
CNEE	National Electric Energy Commission of Guatemala
COD	Commercial Operation Date
Company	Ormat Technologies, Inc., a Delaware corporation, and its consolidated subsidiaries
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
Cyrq	Cyrq Energy, Inc.
DEG	Deutsche Investitions-und Entwicklungsgesellschaft mbH
DFIs	Development Finance Institutions
DOE	U.S. Department of Energy
DOGGR	California Division of Oil, Gas, and Geothermal Resources
DSCR	Debt Service Coverage Ratio
DSIRE	Database of State Incentives for Renewables and Efficiency
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	Electricite de France S.A.

EGS	Enhanced Geothermal Systems
EIB	European Investment Bank
ENEE	Empresa Nacional de Energía Eléctrica
Enthalpy	The total energy content of a fluid; the heat plus the mechanical energy content of a fluid (such as a geothermal brine), which, for example, can be partially converted to mechanical energy in an Organic Rankine Cycle.

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Term	**Definition**
EPA	U.S. Environmental Protection Agency
EPC	Engineering, procurement and construction
EPS	Earnings per share
ERC	Kenyan Energy Regulatory Commission
ERCOT	Electric Reliability Council of Texas, Inc.
ESC	Energy Sales Contract
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	U.S. Federal Energy Regulatory Commission
FIT	Feed-in Tariff
FPA	U.S. Federal Power Act, as amended
GAAP	Generally accepted accounting principles
GCCU	Geothermal Combined Cycle Unit
GDC	Geothermal Development Company
GEA	Geothermal Energy Association
Geothermal Power Plant	The power generation facility and the geothermal field
Geothermal Steam Act	U.S. Geothermal Steam Act of 1970, as amended
GHG	Greenhouse gas
GNP	Gross National Product
GTM	Green Tech Media
GW	Giga watt
GWh	Giga watt hour
HELCO	Hawaii Electric Light Company
IFC	International Finance Corporation
IID	Imperial Irrigation District
ILA	Israel Land Administration
INDE	Instituto Nacional de Electrification
IOUs	investor-owned utilities
IPPs	Independent Power Producers
ISO	International Organization for Standardization
ITC	Investment tax credit
ITC Cash Grant	Payment for Specified Renewable Energy property in lieu of Tax Credits under Section 1603 of the ARRA
JBIC	Japan Bank for International Cooperation
John Hancock	John Hancock Life Insurance Company (U.S.A.)
JOC	Joined operation contract
JPM	JPM Capital Corporation
KenGen	Kenya Electricity Generating Company Ltd.
Kenyan Energy Act	Kenyan Energy Act, 2006
KETRACO	Kenya Electricity Transmission Company Limited
KLP	Kapoho Land Partnership
KPLC	Kenya Power and Lighting Co. Ltd.
kVa	Kilovolt-ampere
kW	Kilowatt - A unit of electrical power that is equal to 1,000 watts
kWh	Kilowatt hour(s), a measure of power produced
LCOE	Levelized Costs of Energy

LSEs	Load Serving Entities
Mammoth Pacific	Mammoth-Pacific, L.P.
MACRS	Modified Accelerated Cost Recovery System
MEMR	Ministry of Energy and Mineral Resources
MIGA	Multilateral Investment Guarantee Agency, a member of the World Bank Group
MW	Megawatt - One MW is equal to 1,000 kW or one million watts
MWh	Megawatt hour(s), a measure of energy produced

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Term	**Definition**
NBPL	Northern Border Pipe Line Company
NIS	New Israeli Shekel
NOC	network operations center
NGI	Natural Gas-California SoCal-NGI Natural Gas price index
NV Energy	NV Energy, Inc.
NYSE	New York Stock Exchange
NYISO	New York Independent System Operator, Inc.
OEC	Ormat Energy Converter
OFC	Ormat Funding Corp., a wholly owned subsidiary of the Company
OFC Senior Secured Notes	$190,000,000 8.25% Senior Secured Notes, due 2020 issued by OFC
OFC 2	OFC 2 LLC, a wholly owned subsidiary of the Company
OFC 2 Senior Secured Notes	Up to $350,000,000 Senior Secured Notes, due 2034 issued by OFC 2
OMPC	Ormat Momotombo Power Company, a wholly owned subsidiary of the Company
Opal Geo	Opal Geo LLC
OPC	OPC LLC, a consolidated subsidiary of the Company
OPC Transaction	Financing transaction involving four of our Nevada power plants in which institutional equity investors purchased an interest in our special purpose subsidiary that owns such plants.
OPIC	Overseas Private Investment Corporation
OrCal	OrCal Geothermal Inc., a wholly owned subsidiary of the Company
OrCal Senior Secured Notes	$165,000,000 6.21% Senior Secured Notes, due 2020 issued by OrCal
Organic Rankine Cycle	A process in which an organic fluid such as a hydrocarbon or fluorocarbon (but not water) is boiled in an evaporator to generate high pressure vapor. The vapor powers a turbine to generate mechanical power. After the expansion in the turbine, the low pressure vapor is cooled and condensed back to liquid in a condenser. A cycle pump is then used to pump the liquid back to the vaporizer to complete the cycle. The cycle is illustrated in the figure below:
Ormat International	Ormat International Inc., a wholly owned subsidiary of the Company
Ormat Nevada	Ormat Nevada Inc., a wholly owned subsidiary of the Company
Ormat Systems	Ormat Systems Ltd., a wholly owned subsidiary of the Company
ORPD	ORPD LLC, a holding company subsidiary of the Company in which Northleaf Geothermal Holdings, LLC holds a 36.75% equity interest
ORPD Transaction	Financing transaction involving the Puna complex and Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants in which Northleaf Geothermal Holdings, LLC purchased an equity interest in our special purpose subsidiary that owns such plants.
OrPower 4	OrPower 4 Inc., a wholly owned subsidiary of the Company
Ortitlan	Ortitlan Limitada, a wholly owned subsidiary of the Company
ORTP	ORTP, LLC, a consolidated subsidiary of the Company

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Term	**Definition**
ORTP Transaction	Financing transaction involving power plants in Nevada and California in which an institutional equity investor purchased an interest in our special purpose subsidiary that owns such plants.
Orzunil	Orzunil I de Electricidad, Limitada, a wholly owned subsidiary of the Company
PEC	Portfolio Energy Credits
PG&E	Pacific Gas and Electric Company
PGV	Puna Geothermal Venture, a wholly owned subsidiary of the Company
PJM	PJM Interconnection, L.L.C.
PLN	PT Perusahaan Listrik Negara
Power plant equipment	Interconnection equipment, cooling towers for water cooled power plant, etc., including the generating units
PPA	Power purchase agreement
ppm	Part per million
PTC	Production tax credit
PUA	Israeli Public Utility Authority
PUCH	Public Utilities Commission of Hawaii
PUCN	Public Utilities Commission of Nevada
PUHCA	U.S. Public Utility Holding Company Act of 1935
PUHCA 2005	U.S. Public Utility Holding Company Act of 2005
PURPA	U.S. Public Utility Regulatory Policies Act of 1978
Qualifying Facility(ies)	Certain small power production facilities are eligible to be “Qualifying Facilities” under PURPA, provided that they meet certain power and thermal energy production requirements and efficiency standards. Qualifying Facility status provides an exemption from PUHCA 2005 and grants certain other benefits to the Qualifying Facility
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
REG	Recovered Energy Generation
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SaaS	Software as a Service
SCADA	Supervisory Control and Data Acquisition
SCPPA	Southern California Public Power Authority
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
Senior Unsecured Bonds	7% Senior Unsecured Bonds Due 2017 issued by the Company
SO#4	Standard Offer Contract No. 4
SOL	Sarulla Operations Ltd.
Solar PV	Solar photovoltaic
SOX Act	Sarbanes-Oxley Act of 2002
Southern California Edison	Southern California Edison Company
SPE(s)	Special purpose entity(ies)
SRAC	Short Run Avoided Costs
	Southern California Edison Company

Southern California Edison	
SPE(s)	Special purpose entity(ies)
SRAC	Short Run Avoided Costs
Union Bank	Union Bank, N.A.
U.S.	United States of America
U.S. Treasury	U.S. Department of the Treasury
VEI	Viridity Energy, Inc.
Viridity	Viridity Energy Solutions Inc., our wholly owned subsidiary
WHOH	Waste Heat Oil Heaters

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Cautionary Note Regarding Forward-Looking Statements

This annual report 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 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 annual report, the words “may”, “will”, “could”, “should”, “expects”, “plans”, “anticipates”, “believes”, “estimates”, “pr “projects”, “potential”, or “contemplate” or the negative of these 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 annual report are primarily located in the material set forth under the headings Item 1 — “Business” contained in Part I of this annual report, Item 1A — “Risk Factors” contained in Part I of this annual report, Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” contained in Part II of this annual report, and “Notes to Financial Statements” contained in Item 8 — “Financial Statements and Supplementary Data” contained in Part II of this annual report, 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 annual report completely and with the understanding that actual future results and developments may be materially different from what we expect due to a number of risks and uncertainties, many of which are beyond our control. Other than as required by law, we will not update forward-looking statements even though our situation may change in the future.

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 annual report;
- geothermal resource risk (such as the heat content, useful life and geological formation of the reservoir);
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- financial market conditions and the results of financing efforts;
- the impact of fluctuations in oil and natural gas prices and competition with other renewable sources on the energy price component under certain of our PPAs;

risks and uncertainties with respect to our ability to implement strategic goals or initiatives in segments of the clean energy industry or new or additional geographic focus areas;

risk and uncertainties associated with our future development of storage projects which may operate as "merchant" facilities without long-term sales agreements, including the variability of revenues and profitabilty of such projects;

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

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

contract counterparty risk;

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

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 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;

there can be no assurance regarding when, if and to what extent opportunities under our commercial cooperation agreement with ORIX Corporation will in fact materialize;

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

our new strategic plan to expand our geographic markets, customer base and product and service offerings may not be implemented as currently planned or may not achieve our goals as and when implemented;

development and construction of Solar PV and energy storage 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; 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.

PART I

ITEM 1. BUSINESS

Certain Definitions

Unless the context otherwise requires, all references in this annual report to "Ormat", "the Company", "we", "us", "our company", "Ormat Technologies", or "our" refer to Ormat Technologies, Inc. and its consolidated subsidiaries. A glossary of certain terms and abbreviations used in this annual report appears at the beginning of this report.

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Overview

We are a leading vertically integrated company that is currently primarily engaged in the geothermal and recovered energy power business. With the objective of becoming a leading global provider of renewable energy, we focus on several key initiatives, under our new strategic plan, as described below.

We design, develop, build, sell, own, and operate clean, environmentally friendly geothermal and recovered energy-based power plants, usually 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 we have built all of our recovered energy-based plants. We recently expanded our operations to include the provision of services in the energy storage, demand response and energy management markets. We currently conduct our business activities in two business segments:

In the Electricity segment we develop, build, own and operate geothermal and recovered energy-based power plants in the U.S. and geothermal power plants in other countries around the world and sell the electricity they generate. We also provide energy storage, demand response and energy management related services through our Viridity business; and

In the Product segment we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation and remote power units and provide services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy-based power plants and in the future, other power generating units such as Solar PV and energy storage

In March 2017, we expanded our Electricity segment operations by entering the energy storage, demand response and energy management markets following the acquisition of substantially all of the business and assets of Viridity Energy, Inc. (VEI), a Philadelphia-based company. The acquired business and assets are owned and operated by our wholly owned subsidiary Viridity Energy Solutions Inc. (Viridity). We intend to use our Viridity business to accelerate long-term growth, expand our market presence in a growing market, and further develop our energy storage, demand response and energy management services, including the VPower™ software platform. We plan to continue providing services and products to existing Viridity customers, while expanding our service offerings to include development and EPC into new regions and targeting a broader potential customer base.

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The map below shows our worldwide portfolio of operating geothermal and recovered energy power plants as of March 1, 2018.

The charts below show the relative contributions of the Electricity segment and the Product segment to our consolidated revenues and the geographical breakdown of our segment revenues for the fiscal year ended December 31, 2017. Additional information concerning our segment operations, including year-over-year comparisons of revenues, the geographical breakdown of revenues, cost of revenues, results of operations, and trends and uncertainties is provided below in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 — "Financial Statements and Supplementary Data".

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The following chart sets forth a breakdown of our revenues for each of the years ended December 31, 2017 and 2016:

The following chart sets forth the geographical breakdown of revenues attributable to our Electricity and Product segments for each of the years ended December 31, 2017 and 2016:

Note: Electricity segment revenues for 2017 in the "Segment Contribution to Revenue" and "Geographic Breakdown of the Electricity Segment Revenue" charts above include our energy storage and demand response activity.

Most of the power plants that we currently own or operate produce electricity from geothermal energy sources. Geothermal energy is a clean, renewable and generally sustainable form of energy derived from the natural heat of the earth. Unlike electricity produced by burning fossil fuels, electricity produced from geothermal energy sources is produced without emissions of certain pollutants such as nitrogen oxide, and with far lower emissions of other pollutants such as carbon dioxide. As a result, electricity produced from geothermal energy sources contributes significantly less to global warming and local and regional incidences of acid rain than energy produced by burning fossil fuels. In addition, compared to power plants that utilize other renewable energy sources, such as wind or solar, geothermal power plants are generally available all the time and can provide base-load electricity services. They can also be custom built to provide a range of services such as baseload, voltage regulation, reserves and flexible capacity. Geothermal energy is also an attractive alternative to other sources of energy as part of a national diversification strategy to avoid dependence on any one energy source or politically sensitive supply sources.

In addition to our geothermal energy business, we manufacture products that produce electricity from recovered energy or so-called “waste heat”. We also construct, own, and operate recovered energy-based power plants. Recovered energy comes from residual heat that is generated as a by-product of gas turbine-driven compressor stations, solar thermal units and a variety of industrial processes, such as cement manufacturing. Such residual heat, which would otherwise be wasted, may be captured in the recovery process and used by recovered energy power plants to generate electricity without burning additional fuel and without additional emissions.

Since 2015, we have implemented a number of elements of our new multi-year strategic plan which was reviewed by our Board of Directors (the “Board”) in 2017. We expect the plan to evolve over time in response to market conditions and other factors. At this time, however, we expect that our primary focus will be as follows:

Expand our geothermal geographical reach. While we continue to evaluate opportunities worldwide, we currently see, Honduras, New Zealand, Philippines, Chile, Indonesia, Turkey, Kenya, Guatemala, China and Ethiopia as very attractive geothermal markets for us. We are actively looking at ways to expand our presence in those countries. In addition, we are looking to expand and accelerate growth through acquisitions and other investments, both domestically and globally, such as our recent acquisition of a geothermal power plant in Guadeloupe in the Caribbean and our recent announcement of the execution of a definitive agreement to acquire U.S. Geothermal Inc., which has three operating power plants in the U.S.

Expand into new technologies. We ultimately hope to be able to leverage our technological capabilities over a variety of renewable energy platforms, including solar power generation and energy storage. Initially, however, we expect that our primary focus will be on expanding our core geothermal competencies to provide high efficiency solutions for high enthalpy applications by utilizing our binary enhanced cycle and technology, as well as expanding into steam geothermal generation equipment and facilities. We may acquire companies with technological and integration capabilities we do not currently have, or develop new technology ourselves, where we can effectively leverage our expertise to implement this part of our strategic plan.

Expand our customer base. We are evaluating a number of strategies for expanding our customer base to C&I customers. In the near term, however, we expect that a majority of our revenues will continue to be generated as they currently are, with our traditional electrical utility customer base for the Electricity segment and our on-going business development efforts for new customers for our Product segment.

While we believe that long-term growth can be realized through our transformational efforts over time, there is no assurance if and when we will meet our objective to become a leading global provider of renewable energy or that such efforts will result in long-term growth. We see these new initiatives as incremental measures to enhance shareholder value. While we implement the plan, we expect to continue, and expand, through organic growth, acquisitions, and other measures, our current business lines both in the Electricity and Product segments as well as other business lines as described above.

Company Contact and Sources of Information

We file annual, quarterly and periodic reports, proxy statements and other information with the SEC. You may obtain and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington D.C. 20549. You may obtain information on the operation of the SEC's Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website at http://www.sec.gov that contains reports, proxy and other information statements, and other information regarding issuers that file electronically with the SEC. Our SEC filings are accessible via the internet at that website.

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Our reports on Form 10-K, 10-Q and 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available through our website at www.ormat.com for downloading, free of charge, as soon as reasonably practicable after these reports are filed with the SEC. Our Code of Business Conduct and Ethics, Code of Ethics Applicable to Senior Executives, Audit Committee Charter, Corporate Governance Guidelines, Nominating and Corporate Governance Committee Charter, Compensation Committee Charter, and Insider Trading Policy, as amended, are also available at our website address mentioned above. If we make any amendments to our Code of Business Conduct and Ethics or Code of Ethics Applicable to Senior Executives or grant any waiver, including any implicit waiver, from a provision of either code applicable to our Chief Executive Officer, Chief Financial Officer or principal accounting officer requiring disclosure under applicable SEC rules, we intend to disclose the nature of such amendment or waiver on our website. The content of our website, however, is not part of this annual report.

You may request a copy of our SEC filings, as well as the foregoing corporate documents, at no cost to you, by writing to the Company address appearing in this annual report or by calling us at (775) 356-9029.

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Our Power Generation Business (Electricity Segment)

Power Plants in Operation

The table below summarizes certain key non-financial information relating to our power plants and complexes as of March 1, 2018. The generating capacity of certain of our power plants and complexes listed below has been updated from our 2016 disclosure to reflect changes in the resource temperature and other factors that impact resource capabilities:

Type	**Region**	**Plant**	**Ownership**[(1)]	**Generating capacity (MW)** [(2)]	**Region 2016 Capacity Factor**
Geothermal	California	Ormesa Complex	100%	40	
		Heber Complex	100%	89	
		Mammoth Complex	100%	29	
		Brawley	100%	13	
					77%
	West Nevada	Steamboat Complex	100%	70	
		Brady Complex	100%	18	
					87%
	East Nevada	Tuscarora	100%	18	
		Jersey Valley	100%	10	
		McGinness Hills	100%	90	
		Don A. Campbell	63.3%	41	
		Tungsten Mountain	100%	26[(3)]	
					94%
	Hawaii	Puna	63.3%	38	
					97%
	International	Amatitlan (Guatemala)	100%	20	
		Zunil (Guatemala)	97%	23	
		Olkaria III Complex (Kenya)	100%	139	
		Bouillante (Guadeloupe Island)	60%[(4)]	15	
		Platanares (Honduras)	100%	35[(5)]	
					94%
Total Consolidated Geothermal				714	88%
Unconsolidated Geothermal	Indonesia	Sarulla (SIL & NIL 1)	12.75%	28	

REG	OREG 1	63.3%	22	
	OREG 2	63.3%	22	
	OREG 3	63.3%	5.5	
	OREG 4	100%	3.5[(6)]	
Total REG			53	84%
Total			**795**	

1. We indirectly own and operate all of our power plants, although financial institutions hold equity interests in one of our subsidiaries, Opal Geo, which owns the McGinness Hills geothermal power plant complex, the Tuscarora and Jersey Valley power plants and the second phase of the Don A. Campbell power plant, all located in Nevada. In the table above, we list these power plants as being 100% owned because all of the generating capacity is owned by Opal Geo and we control the operation of the power plants. The nature of the equity interests held by the financial institution is described below in Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the headings "Opal Geo Transaction".

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Notwithstanding our approximately 60% equity interest in the Bouillante power plant and 63.25% direct equity interest in the Puna, the first phase of Don A. Campbell, OREG 1, OREG 2 and OREG 3 power plants as well as the indirect interest in the second phase of the Don A. Campbell power plant owned by our subsidiary, ORPD LLC ("ORPD"), we list 100% of the generating capacity of the Bouillante power plant and the power plants in the ORPD portfolio in the table above because we control their operation. We list our 12.75% share of the generating capacity of the Sarulla power plant as we own a 12.75% minority interest. The revenues from the Sarulla project are not consolidated and are presented under "Equity in earnings (losses) of investees, net" in our financial statements.

2. References to generating capacity generally refer to the gross generating capacity less auxiliary power in the case of all of our existing power plants, except the Zunil power plant. We determine the generating capacity figures in these power plants by taking into account the resource and power plant capabilities. In the case of the Zunil power plant, revenues are calculated based on a 24 MW capacity unrelated to the actual performance of the reservoir. This column represents our net ownership of such generating capacity.

In any given year, the actual power generation of a particular power plant may differ from that power plant's generating capacity due to variations in ambient temperature, the availability of the resource, and operational issues affecting performance during that year.

3. The 26 MW Tungsten Mountain power plant in Nevada commenced commercial operation on December 1, 2017.

4. We own 60%, and each of CDC and Sageos own 20%, of the Bouillante power plant. We and CDC hold our respective 60% and 20% equity interests in the Bouillante power plant through GB.

5. The 35 MW Platanares power plant in Honduras commenced commercial operation on September 26, 2017.

6. The OREG 4 power plant is not operating at full capacity because of low run time of the compressor station that serves as the power plant's heat source. This results in lower power generation.

All of the revenues that we derive from the sale of electricity are pursuant to long-term PPAs. Approximately 45.8% of our total revenues in the year ended December 31, 2017 were derived from the sale of electricity by our power plants to power purchasers that currently have investment grade credit ratings. The purchasers of electricity from our foreign power plants are either state-owned or private entities.

New Power Plants

We are currently in various stages of construction of new power plants and expansion of existing power plants. Our construction and expansion plan include 72 MW in generating capacity from geothermal power plants in the U.S., Kenya and Indonesia that are fully released for construction. In addition, we have several projects in the U.S., Guadeloupe, Kenya and Honduras that are either under initial stages of construction or under different stages of development with an aggregate capacity of between 115 MW and 120 MW.

We have substantial land positions across 32 prospects in the U.S., Guatemala, Guadeloupe, Kenya, New Zealand, Honduras and Ethiopia that we expect will support future geothermal development, on which we have started or plan to start exploration activity. These land positions are comprised of various leases, exploration concessions for geothermal resources and an option to enter into geothermal leases.

In addition, we are currently developing three storage systems, one behind-the-meter system and two in-front-of-the-meter (IFM) systems in New Jersey.

New activity

On March 15, 2017, we completed the acquisition of our Viridity business as described above.

Our Viridity business currently manages curtailable customer loads of over 875 MW across 3,000 sites under contracts with leading U.S. retail energy providers and directly with large C&I customers, including management of a portfolio of non-utility storage assets located in the northeastern U.S. with over 80,000 operational market hours. We serve our distributed customers through a network operations center (NOC), which is operated 24/7 using our VPowerMarkets™ software platform and a SCADA platform. VPower™ services are provided to customers using a SaaS model under which we receive license fees and/or a portion of the revenue and savings that are achieved for our Viridity customers.

We expect that the eco system we created, combining our Viridity capabilities and our overall capabilities, including among others, our global presence, experience in technology and system integration, EPC of power generation projects, flexible business models, and our reputation and experience in the geothermal and recovered energy sectors, will enable us to expand in the growing energy storage sector.

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In connection with the acquisition of our Viridity business, we assumed certain contractual duties and obligations that are regulated by the Federal Energy Regulatory Commission (FERC) and certain independent system operators (ISOs) and regional transmission organizations (RTOs). Specifically, our Viridity business obtained and maintains authorization from FERC to make wholesale sales of power, capacity, and ancillary services at market-based rates, and we have confirmed membership status with eligibility to serve designated contractual functions within each of the following ISOs and RTOs: PJM Interconnection LLC (PJM), New York Independent System Operator, Inc. (NYISO), and the Electric Reliability Council of Texas (ERCOT). Additionally, during the fourth quarter of 2017, we received formal notice of membership in Midcontinent Independent System Operator (MISO) and ISO New England Inc. and have filed for membership in Independent Electricity System Operator (IESO – Ontario Canada). In the future, we may need to obtain and maintain similar membership and eligibility status with other ISO and RTO markets in which our Viridity business will operate.

Our Product Business (Product Segment)

We design, manufacture and sell products for electricity generation and provide the related services described below. We primarily manufacture products to fill customer orders, but in some situations, we may manufacture products as inventory for future internal and external projects.

Power Units for Geothermal Power Plants. We design, manufacture and sell power units for geothermal electricity generation, which we refer to as OECs. In geothermal power plants using OECs, geothermal fluid (either hot water (also called brine) or steam or both) is extracted from the underground reservoir and flows from the wellhead to a vaporizer that also heats a secondary working fluid, which is vaporized and used to drive the turbine. The secondary fluid is then condensed in a condenser, which may be cooled directly by air or by water from a cooling tower and sent back to the vaporizer. The cooled geothermal fluid is then reinjected back into the reservoir. Our customers include contractors and geothermal power plant developers, owners and operators.

Power Units for Recovered Energy-Based Power Generation. We design, manufacture and sell power units used to generate electricity from recovered energy, or so-called “waste heat”. This heat is generated as a residual by-product of gas turbine-driven compressor stations, solar thermal units and a variety of industrial processes, such as cement manufacturing, and is not otherwise used for any purpose. Our existing and target customers include interstate natural gas pipeline owners and operators, gas processing plant owners and operators, cement plant owners and operators, and other companies engaged in other energy-intensive industrial processes.

EPC of Power Plants. We serve as an EPC contractor for geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered energy-based power units as described above. Unlike many other companies that provide EPC services, we believe we have an advantage in that we are using equipment that we manufacture and thus have better quality and better control over the timing and delivery of required equipment and its related costs.

Remote Power Units and Other Generators. We design, manufacture and sell fossil fuel powered turbo-generators with capacities ranging from 200 watts to 5,000 watts, which operate unattended in extreme hot or cold climate conditions. Our customers include contractors who install gas pipelines in remote areas and off-shore platforms operators and contractors. In addition, we design, manufacture, and sell generators, including heavy duty direct-current generators, for various other uses. We are in the process of slowing down these activities.

History

Ormat Technologies, Inc. was formed as a Delaware corporation in 1994 by our former parent company Ormat Industries. Ormat Industries was one of the first companies to focus on the development of equipment for the production of clean, renewable and generally sustainable forms of energy. On February 12, 2015, we successfully completed the acquisition of Ormat Industries in an all-stock merger, eliminating its majority ownership and control of Ormat Technologies.

Industry Background

Geothermal Energy

Most of our power plants in operation produce electricity from geothermal energy. There are several different sources or methods of obtaining geothermal energy, which are described below.

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Hydrothermal geothermal-electricity generation — Hydrothermal geothermal energy is derived from naturally occurring hydrothermal reservoirs that are formed when water comes sufficiently close to hot rock to heat the water to temperatures of 300 degrees Fahrenheit or more. The heated water then ascends toward the surface of the earth where, if geological conditions are suitable for its commercial extraction, it can be extracted by drilling geothermal wells. Geothermal production wells are normally located within several miles of the power plant, as it is not economically viable to transport geothermal fluids over longer distances due to heat and pressure loss. The geothermal reservoir is a renewable source of energy if: (i) natural ground water sources and reinjection of extracted geothermal fluids are adequate over the long-term to replenish the geothermal reservoir following the withdrawal of geothermal fluids and (ii) the well field is properly operated. Geothermal energy power plants typically have higher capital costs (primarily as a result of the costs attributable to well field development) but tend to have significantly lower variable operating costs (principally consisting of maintenance expenditures) than fossil fuel-fired power plants that require ongoing fuel expenses.

EGS — An EGS is a subsurface system that may be artificially created to extract heat from hot rock where the permeability and aquifers required for a hydrothermal system are insufficient or non-existent. A geothermal power plant that uses EGS techniques recovers the thermal energy from the subsurface rocks by creating or accessing a system of open fractures in the rock through which water can be injected, heated through contact with the hot rock, returned to the surface in production wells and transferred to a power unit.

Co-produced geothermal from oil and gas fields, geo-pressurized resources — Another source of geothermal energy is hot water produced as a by-product of oil and gas extraction. When oil and gas wells are deep, the extracted fluids are often at high temperatures and if the water volume associated with the extracted fluids is significant, the hot water can be used for power generation in equipment similar to a geothermal power plant.

Geothermal Power Plant Technologies

Geothermal power plants generally employ either binary systems or conventional flash design systems, as briefly described below. In our geothermal power plants, we also employ our proprietary technology of combined geothermal cycle systems.

Binary System

In a geothermal power plant using a binary system, geothermal fluid (either hot water (also called brine) or steam or both) is extracted from the underground reservoir and flows from the wellhead through a gathering system of insulated steel pipelines to a vaporizer that also heats a secondary working fluid. This is typically an organic fluid, such as pentane or butane, which is vaporized and is used to drive the turbine. The organic fluid is then condensed in a condenser, which may be cooled directly by air or by water from a cooling tower and sent back to the vaporizer through a pump. The cooled geothermal fluid is then reinjected back into the reservoir. The operation of our air-cooled binary geothermal power plant is depicted in the diagram below.

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Flash Design System

In a geothermal power plant using flash design, geothermal fluid is extracted from the underground reservoir and flows from the wellhead through a gathering system of insulated steel pipelines to flash tanks and/or separators. There, the steam is separated from the brine and is sent to a demister, where any remaining water droplets are removed. This produces a stream of dry saturated steam, which drives a steam turbine generator to produce electricity. In some cases, the brine at the outlet of the separator is flashed a second time (dual flash), providing additional steam at lower pressure used in the low pressure section of the steam turbine to produce additional electricity. Steam exhausted from the steam turbine is condensed in a surface or direct contact condenser cooled by cold water from a cooling tower. The non-condensable gases (such as carbon dioxide) are removed by means of a vacuum system in order to maintain the performance of the steam condenser. The resulting condensate is used to provide make-up water for the cooling tower. The hot brine remaining after separation of steam is injected (either directly or after passing through a binary plant to produce additional power from the residual heat remaining in the brine) back into the geothermal resource through a series of injection wells. The flash technology is depicted in the diagram below.

In some instances, the wells directly produce dry steam and the steam is fed directly to the steam turbine with the rest of the system similar to the flash technology described above.

Our Proprietary Technology

Our proprietary technology may be used either in power plants operating according to the Organic Rankine Cycle alone or in combination with various other commonly used thermodynamic technologies that convert heat to mechanical power, such as gas and steam turbines. It can be used with a variety of thermal energy sources, such as geothermal, recovered energy, biomass, solar energy and fossil fuels. Specifically, our technology involves original designs of turbines, pumps, and heat exchangers, as well as formulation of organic motive fluids (all of which are non-ozone-depleting substances). Using advanced computational fluid dynamics techniques and other computer aided design software as well as our test facilities, we continuously seek to improve power plant components, reduce operations and maintenance costs, and increase the range of our equipment and applications. We are always examining ways to increase the output of our plants by utilizing evaporative cooling, cold reinjection, configuration optimization, and topping turbines. In the geothermal as well as the recovered energy (waste heat) areas, we are examining two-level and three-level energy systems and other thermodynamic cycle alternations along with new motive fluids.

We also developed, patented and constructed GCCU power plants in which the steam first produces power in a backpressure steam turbine and is subsequently condensed in a vaporizer of a binary plant, which produces additional power. Our Geothermal Combined Cycle technology is depicted in the diagram below.

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In the conversion of geothermal energy into electricity, our technology has a number of advantages over conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer and requiring cooling water treatment with chemicals and thus a need for the disposal of such chemicals. A conventional geothermal steam turbine plant also creates a significant visual impact in the form of an emitted plume from the cooling towers, especially during cold weather. By contrast, our binary and combined cycle geothermal power plants have a low profile with minimal visual impact and do not emit a plume when they use air-cooled condensers. Our binary and combined cycle geothermal power plants reinject all of the geothermal fluids utilized in the respective processes into the geothermal reservoir. Consequently, such processes generally have no emissions.

Other advantages of our technology include simplicity of operation and maintenance and higher yearly availability. For instance, the OEC employs a low speed and high efficiency organic vapor turbine directly coupled to the generator, eliminating the need for reduction gear. In addition, with our binary design, there is no contact between the turbine blade and geothermal fluids, which can often be very corrosive and erosive. Instead, the geothermal fluids pass through a heat exchanger, which is less susceptible to erosion and can adapt much better to corrosive fluids. In addition, with the organic vapor condensed above atmospheric pressure, no vacuum system is required.

We use the same elements of our technology in our recovered energy products. The heat source may be exhaust gases from a Brayton cycle gas turbine, low-pressure steam, or medium temperature liquid found in the process industries such as oil refining and cement manufacturing. In most cases, we attach an additional heat exchanger in which we circulate thermal oil or water to transfer the heat into the OEC's own vaporizer in order to provide greater operational flexibility and control. Once this stage of each recovery is completed, the rest of the operation is identical to that of the OECs used in our geothermal power plants and enjoys the same advantages of using the Organic Rankine Cycle. In addition, our technology allows for better load following than conventional steam turbines, requires no water treatment (since it is air cooled and organic fluid motivated), and does not require the continuous presence of a licensed steam boiler operator on site.

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Our REG technology is depicted in the diagram below.

Patents

We have 77 U.S. patents that are in force (and have approximately 9 U.S. patents pending). These patents and patent applications cover our products (mainly power units based on the Organic Rankine Cycle) and systems (mainly geothermal power plants and industrial waste heat recovery plants for electricity production). The products-related patents cover components that include turbines, heat exchangers, seals and controls as well as control of operation of geothermal production well pumps. The system-related patents cover not only particular components but also the overall energy conversion system from the “fuel supply” (e.g., geothermal fluid, waste heat, biomass or solar) to electricity production.

The system-related patents also cover subjects such as waste heat recovery related to gas pipeline compressors and industrial waste heat, solar power systems, disposal of non-condensable gases present in geothermal fluids, power plants for very high pressure geothermal resources, two-phase fluids, low temperature geothermal brine as well as processes related to EGS. A number of our patents cover combined cycle geothermal power plants, in which the steam first produces power in a backpressure steam turbine and is subsequently condensed in a vaporizer of a binary plant, which produces additional power. The remaining terms of our patents range from one year to 16 years. The loss of any single patent would not have a material effect on our business or results of operations.

Research and Development

We are conducting research and development activities intended to improve plant performance, reduce costs, and increase the breadth of our product offerings. The primary focus of our research and development efforts is targeting power plant conceptual thermodynamic cycle and major equipment including continued performance, cost and land usage improvements to our condensing equipment, and development of new higher efficiency and higher power output turbines.

Our Viridity business continues to develop new optimization algorithms to optimize the life of a battery energy storage system (BESS), to optimize our and our customers’ economic return and to forecast the trends surrounding our customers’ electricity consumption and the electric grid including times of peak demands and the usage of ancillary services.

We have also focused our development efforts on the engineering and design of improved energy storage systems. These development efforts include, among others, further development of the control hardware and software for energy storage systems to follow electric grid and market signals and to optimize their delivery of energy into the markets using our VPower™ software and SCADA platform to accelerate system optimization through cloud base algorithms.

We have developed, and continue to develop, system integration capabilities that match the appropriate system and system sizing with the appropriate battery chemistry, electrical and physical components to accommodate our needs or needs of the customers that will own such energy storage systems in light of the markets in which they will operate. We are searching for alternative chemistries, products and combinations of hybrid solutions to best address our energy storage product customers' needs.

Additionally, we are continuing to evaluate investment opportunities in new companies with technology and/or product offerings for renewable energy and energy storage solutions.

Market Opportunity

Geothermal Market Opportunities

United States

Interest in geothermal energy in the U.S. remains strong for numerous reasons, including legislative support, RPS goals, coal and nuclear base-load retirements, and increasing awareness of the positive value of geothermal characteristics as compared to intermittent renewable technologies.

Today, electricity generation from geothermal resources is concentrated mainly in California, Nevada, Hawaii, Idaho, Oregon, and Utah, and we believe there are opportunities for development in other states such as New Mexico due to the potential of their geothermal resources.

In a report issued in March 2016, the GEA indicated that the U.S. geothermal industry had about 3,700 MW of installed nameplate capacity and over 80 active projects with a cumulative capacity of over 1,250 MW of geothermal projects under various phases of consideration or development in 10 U.S. states.

Geothermal energy provides numerous benefits to the U.S. grid and economy, according to another GEA report issued in January 2017. Geothermal development and operation brings economic benefits in the form of taxes and long term high-paying jobs, and it currently has one of the lowest LCOE of all power sources in the U.S. Additionally, improvements in geothermal production make it possible to provide ancillary and on-demand services. This helps load serving entities avoid additional costs from purchasing and then balancing intermittent resources with storage or new transmission.

State level legislation

In response to increasing demand for “green” energy, many states have adopted legislation requiring, and providing incentives for, electric utilities to sell electricity generated from renewable energy sources. In the U.S., 37 states plus the District of Colombia and four territories have enacted an RPS, renewable portfolio goals, or similar laws requiring or encouraging utilities in such states to generate or buy a certain percentage of their electricity from renewable energy or recovered heat sources.

According to the Database of State Incentives for Renewables and Efficiency (DSIRE), 30 states (including California, Nevada, and Hawaii, where we have been the most active in our geothermal energy development and in which all of our operating U.S. geothermal power plants are located), two territories, and the District of Columbia define geothermal resources as “renewable”. In addition, according to the EPA, 25 states have enacted RPS, Clean Energy Standards, Energy Efficiency Resource Standards or Alternative Portfolio Standards program guidelines that include some form of combined heat and power and/or waste heat recovery.

We see the impact of RPS legislation as the most significant driver for us to expand existing power plants and to build new projects.

California

California’s RPS program now requires Load Serving Entities (LSEs), including investor-owned utilities (IOUs), electric service providers, community choice aggregators, and publicly owned utilities to increase their share of procurement from eligible renewable energy resources as a percentage of their total procurement. The RPS requires LSEs to procure 33 percent of their energy from renewable resources by 2020, ramping up to 50 percent in 2030, with interim targets of 40 percent by 2024 and 45 percent by 2027. The expanded RPS target should benefit geothermal energy, which has the advantage of generating flexible base load power, helping California diversify its mix of renewable resources.

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In 2014, AB 2363 became effective, requiring the CPUC to adopt, by December 31, 2015, a methodology for determining the costs of integrating eligible renewable energy resources. The process has experienced some delays, and currently, the CPUC is incorporating the development of this methodology into its Integrated Resource Planning process. While the CPUC has issued draft guidelines for integrated resource planning in late 2017, the renewable integration issues assessment remain unresolved. The CPUC has implemented a capacity assessment mechanism that tends to favor dispatchable resources, including geothermal, giving them a higher overall capacity value than variable resources such as wind and solar.

Nevada

In 2016, Nevada's RPS required that at least 20% of electricity sold to Nevada retail customers be from renewable energy resources and credits, and at least 6% of that amount be from solar resources. According to NV Energy's Annual RPS Compliance Report, in 2016, both Nevada Power and Sierra Pacific Power exceeded 2016 RPS standard requirements, achieving a total of 22.2% and 26.6% respectively.

Hawaii

Hawaii established a renewable portfolio goal in 2001. Since 2001, the RPS targets were revised and expanded. On June 2015, Hawaii became the only state with a legislative goal of 100% renewable energy by 2045 with the signing of HB 623. The new policy includes interim requirements of 15% by the end of 2015, 30% by the end of 2020, 40% by 2030, and 70% by 2040, ultimately reaching 100% renewable electricity by 2045.

In 2016, Hawaiian Electric Company and its subsidiaries exceeded the 2015 RPS requirement, achieving a consolidated RPS of 25.8% of retail electricity sales from eligible renewable energy resources.

Federal level legislation

On August 3, 2015, President Obama and the EPA announced the Clean Power Plan that sets standards for power plants and customized goals for states to cut carbon pollution. The goal of the proposed plan includes cutting carbon emissions from the power sector by 32% below 2005 levels nationwide by 2030. In February 2016, the Supreme Court of the U.S. granted a temporary stay halting implementation of the Clean Power Plan pending resolution of legal challenges to the proposed plan. The U.S. Court of Appeals for the District of Columbia Circuit heard oral arguments in the cases challenging the Clean Power Plan on September 27, 2016.

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which in part calls for a review of the Clean Power Plan. On October 10, 2017, the EPA issued a Notice of Proposed Rulemaking (NPRM), proposing to repeal the Clean Power Plan. After reviewing the Clean Power Plan, the EPA has proposed to determine that the Obama-era regulation exceeds the agency's statutory authority.

The federal government encourages production of electricity from geothermal resources or solar energy through certain tax subsidies. For a new geothermal power plant in the U.S. that started construction by December 31, 2017, we are permitted to claim an investment tax credit for 30 percent of the project cost in the year the project is put in service or production tax credits over time on the power produced. The production-based credits, which in 2017 were 2.4 cents per kWh, are adjusted annually for inflation and may be claimed for 10 years on the net electricity output sold to third parties after the project is first placed in service. Any project that started construction by December 2017 must ordinarily be put in service within four years after the end of the year in which construction started to qualify for tax credits at these rates. For a new geothermal power plant in the U.S. that started construction after 2017, we are permitted to claim an investment tax credit of 10 percent of the project cost.

New solar projects that are under construction by December 2019 will qualify for a 30 percent investment tax credit. The credit will fall to 26 percent for projects starting construction in 2020 and 22 percent for projects starting construction in 2021. Projects that are under construction before these deadlines must be placed in service by December 31 2023 to qualify for investment tax credits at these rates. Solar projects placed in service after December 31, 2023 will only qualify for a 10 percent investment tax credit, on par with the permanent credit provided to geothermal. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward.

The tax credits are potentially exposed to claw back under a new base erosion and anti-abuse tax or "BEAT" that took effect on January 1, 2018. See the discussion under Item 1A — “Risk Factors”.

New U.S. federal tax legislation, commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”), enacted at the end of December 2017 reduced the corporate income tax rate from 35 percent to 21 percent starting in 2018. This is likely to reduce the amount of tax equity that can be raised to finance renewable energy projects but should increase after-tax earnings from operating projects after the initial period when the project is being depreciated.

The Tax Act also allows the cost of new or used equipment purchased from third parties to be "expensed" or deducted immediately. This change applies to equipment put in service after September 27, 2017. However, it does not apply to equipment that we contracted to acquire on or before September 27. This full expensing applies to equipment put in service through 2022. After that, the percentage that can be expensed drops by 20 percent a year until it reaches zero in 2027.

There are other changes in the Tax Act that are potentially favorable to us, such as U.S. corporations will no longer be taxed on dividends from foreign corporations in which they own at least a 10 percent interest to the extent the dividends are paid out of future earnings earned outside the U.S., and income from cross-border sales of turbines and other "inventory" will be treated as earned in the country where the items were manufactured rather than earned partially or entirely in the country where the inventory is sold. There are also other potentially unfavorable provisions, such as a new annual tax on global intangible low--taxed income, or "GILTI." We have not yet made a full assessment of the impact of the Tax Act on our future earnings or operations. See Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for further discussion.

Global

We believe the global markets continue to present growth and expansion opportunities in both established and emerging markets.

According to the GEA's Geothermal Power: International Market Update, the global geothermal market was developing about 2.5 GW of planned capacity spread across 23 countries. Additionally, the GEA estimates that, based on current data, the global geothermal industry is expected to grow from 13.8 GW today to reach 23 GW by 2021.

The assessment conducted by the GEA is only an estimate that is based on projects and resource reporting by the geothermal industry. A developer's ability to fully develop a geothermal resource is dependent upon its capabilities to identify the resource and conduct exploration, development and construction; therefore, this estimate may not be accurate. We refer to it only as a possible reference point, but we do not necessarily concur with this estimate.

Operations outside of the U.S. may be subject to and/or benefit from increasing efforts by governments and businesses around the world to fight climate change and move towards a low carbon, resilient and sustainable future. According to a 2017 report from the International Renewable Energy Agency entitled Rethinking Energy, to date, more than 170 countries have established renewable energy targets, and nearly 150 have enacted policies to catalyze investments in renewable energy technologies.

In December 2015, 197 countries signed an historic agreement at the COP21 UN Climate Change Conference held in Paris. For the first time, all countries committed to setting nationally determined climate targets and reporting on their progress. The agreement's aim is to keep global temperature rise this century well below 2 degrees Celsius and to drive efforts to limit the temperature increase even further to 1.5 degrees Celsius above pre-industrial levels. According to the United Nations Framework Convention on Climate Change (UNFCCC), the submission of national targets in five-year cycles signals to investors and technology innovators that the world will demand clean power plants, energy efficient factories and buildings, and low-carbon transportation in the decades to come.

The Paris Agreement entered into force on November 4, 2016, thirty days after the date on which at least 55 parties to the Convention accounting in total for at least an estimated 55% of the total global greenhouse gas emissions deposited their instruments of ratification, acceptance, approval or accession with the Depositary. 127 Parties have ratified of 197 Parties to the Convention.

On June 1, 2017, President Donald J. Trump announced that the U.S. will withdraw from the Paris Climate Accord and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the U.S.

In support of the Paris agreement, the EIB has committed to provide $100 billion of new financing for climate action projects over the five years. The support of multilateral institutions such as EIB is expected to be an important factor in assisting countries in reaching their targets under the Paris Climate Change Agreement.

In November 2015, a group of 20 countries, including the US, UK, France, China and India, pledged to double their budget for renewable energy technology over the next five years as part of a separate initiative called Mission Innovation.

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Also, in November 2015, the Breakthrough Energy Coalition was launched by a group of 28 private investors with the objective of bringing companies with the potential to deliver affordable, reliable and carbon free power from the research lab to the market.

We believe that these developments and governmental plans will create opportunities for us to acquire and develop geothermal power generation facilities internationally, as well as create additional opportunities for our Product segment.

Outside of the U.S., the majority of power generating capacity has historically been owned and controlled by governments. Since the early 1990s, however, many foreign governments have privatized their power generation industries through sales to third parties encouraging new capacity development and/or refurbishment of existing assets by independent power developers. These foreign governments have taken a variety of approaches to encourage the development of competitive power markets, including awarding long-term contracts for energy and capacity to independent power generators and creating competitive wholesale markets for selling and trading energy, capacity, and related products. Some foreign regions and countries have also adopted active government programs designed to encourage clean renewable energy power generation such as the following countries in which we operate and/or are conducting business development activities:

Europe

Turkey is the fastest growing geothermal market worldwide with the theoretical potential for 31 GW of geothermal capacity and with a proven geothermal capacity of 4.5 GW, according to the Turkish Mineral Technical Exploration Agency.

Since 2004, we have established strong relationships in the Turkish market and provided our full range of solutions including our state-of-the-art binary systems to 28 geothermal power plants with a total capacity of nearly 515 MW, of which 6 power plants are currently under construction.

In Turkey, the 'National Renewable Energy Action Plan' proposes to increase the country's renewable energy generation capacity to 61 GW by 2023, including 1.5 GW of electricity generation from geothermal resources. This plan is supported by the European Bank for Reconstruction and Development. The plan aims to increase Turkish energy security by diversifying its energy supply, making greater use of domestic resources, protecting the environment by relying on clean, renewable and low carbon technologies and fostering energy market efficiency through private sector investment and integration.

The plan also seeks to attract private investments in research and development and in geothermal exploitation for electricity production and to provide financial support to innovation and technology research in the field of renewable energy. Special emphasis and attention has been placed on using locally manufactured equipment in renewable energy based generating facilities, with a target set for the amount of major and critical equipment that is manufactured locally to be used in such facilities by the end of 2019.

To achieve its objective of having 30% of its power generated from renewable sources by 2023, Turkey has changed its renewable energy law first enacted in 2007. The law sets the feed-in-tariff (FIT) for electricity generated from geothermal resources at $105 per MWh for ten years from the COD of the relevant project and provides a further incentive of $13 per MWh for local manufacturing of turbine related parts for five years from the COD of the relevant project. This law, as amended, is effective until 2020. Renewable energy producers will also benefit from an 85% discount on transmission costs for 10 years and various priority rights over land usage. In order to benefit from the incentives under the renewable energy law, a renewable energy generation facility must hold a renewable energy resource certificate (the RER Certificate), which is issued by Turkey's Energy Market Regulatory Authority. An RER certificate is valid for the term of the generation license of the relevant generation company. In addition, and to avoid rights and licenses manipulation, a pre-feasibility license must be issued and paid for upon request to hold a concession. These pre-licenses must be converted into full licenses for developed fields within three years of issuance, or they become void and the license rights may be re-assigned without fee reimbursement.

To address the demand for local production, we established a local subsidiary in Turkey, which has obtained all certifications required to be obtained by a local manufacturer of parts and equipment in accordance with the Turkish legislation described above.

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Latin America

Several Latin American countries have renewable energy programs. In November 2013, the national government of Guatemala, where our Zunil and Amatitlan power plants are located, approved a law creating incentives for power generation from renewable energy sources. These incentives include, among other things, providing economic and fiscal incentives such as exemptions from taxes on the importation of relevant equipment and various tax exemptions for companies implementing renewable energy projects. Additionally, the Energy Policy 2013-2027 identifies great untapped potential for renewable energy production in Guatemala, including 1,000 MW for geothermal. One of the main objectives of the Energy Policy is to secure a supply of electricity at competitive prices by diversifying the energy mix with an 80% renewable energy share target for 2027.

In **Honduras**, we recently completed the construction of the first geothermal power plant under a BOT agreement. The national government of Honduras approved the Incentives Act (Decree No.70-2007), which provide incentives in the form of tax exemptions for equipment, materials and services related to power generation development based on renewable resources. At the same time, ENEE, the national integrated utility, will buy energy from such projects and offer to pay rates that are above the marginal cost approved by the CNE. Honduras also set a target to reach at least 80% renewable energy production by 2034.

Mexico is the world’s fourth largest producer of geothermal energy. Recent studies suggest an over 9 GW geothermal potential, of which only approximately 12% is already developed. In December 2013, the Mexican Congress passed a constitutional reform in an attempt to increase the participation of private investors in the generation and commercialization of electric energy. This reform affects the electricity market by opening the generation and commercialization of electricity to private companies, transforming Mexico’s Federal Electricity Commission to a for-profit public company, and redefining the functions and attributions of the Ministry of Energy. The secondary legislation that establishes the attributions of the public entities, procurement regulations, and a normative framework for state-owned energy companies was finalized in 2014.

In July 2015, **Mexico** launched round zero and assigned the projects to be developed by Mexico's state-owned utility CFE, with the remainder to be put out to tender to the private sector. Thirteen geothermal areas and five concessions were given by the Mexican Secretariat of Energy to CFE. The government expects to award private companies with concessions for 30 years and exploration permits for up to 150 km^2 for three years. We are in various discussions with local companies to identify attractive geothermal resources and projects.

Caribbean

Many island nations in general and specifically the **Caribbean** nations, depend almost entirely on petroleum to meet their electricity needs. With an average electricity price of approximately $35 per kWh in 2014, the lack of diversified power generation leaves Caribbean nations vulnerable to commodity market volatility, while the lack of new development leaves them reliant on what are believed to be outdated and often unreliable power plants. The larger issue hindering large-scale renewable energy deployments, however, is scale. Caribbean nations have quite significant renewable energy potential, yet most have small demand. The majority of the Caribbean grids are relatively old, with the average diesel generator more than 20 years old. Furthermore, the power supply is relatively inefficient with high system losses. Due to their sizes, each of the Caribbean countries is generally dominated by one local utility and simple market structures where electricity is regulated directly by local governments. Other than in Guadeloupe, where the geothermal power plant that we recently acquired has been operating since 1985, there are no other operating geothermal projects in the Caribbean region. Recently, some deep well drilling exploration was performed on a few islands, but the results of this exploration are still pending. Although few, we believe there are opportunities for us in the Caribbean islands of St. Kitts, Nevis, St. Lucia, Dominica, and Montserrat.

Oceania

In **New Zealand**, where we have been actively providing geothermal power plant solutions since 1988, the government's policies to fight climate change include an unconditional GHG emissions reduction target of between 10% and 20% below 1990 levels by 2020 and a renewable electricity generation target of 90% of New Zealand's total electricity generation by 2025. We continue selling power plant equipment to our New Zealand customers and secured two projects in the last two years.

South East Asia

Ormat holds a 12.75% equity interest in the Sarulla project in **Indonesia**. The first 110 MW phase commenced commercial operation in March 2017, the second 110 MW phase commenced commercial operation in October 2017, and the third 110 MW phase is currently under construction, with plans to commence commercial operation in the second quarter of 2018.

The **Indonesian** government intends to increase the share of renewable energy sources in the energy mix, aiming to meet a target of 23% of domestic energy demand by 2025. In the IPP sector, certain regulations for geothermal projects have been implemented, providing incentives such as investment tax credits, accelerated depreciation, and pricing guidelines to allow for preferential power prices for generators.

The Indonesian government announced its intention to reduce the country's carbon dioxide emissions by 26% by 2020 at the 2009 United Nations Climate Change Conference in Copenhagen and during 2015 in Paris.

In January 2016, the President of Indonesia issued new presidential regulations (PR No. 4 2016) to accelerate the Indonesian 35 GW Power Generation Program. The regulations introduce a new government guarantee for the development of power projects, which would cover both projects developed by the state-owned utility company, PLN, and those projects developed by PLN in cooperation with IPPs or their subsidiaries. Additionally, a shorter period to obtain necessary permits for development was introduced as well as clarifications that geothermal projects can be developed in high-conservation forest areas (e.g. national parks).

The Indonesian government is planning to revise negative investment regulation. According to Presidential Decree No. 39/2014, the development of geothermal power plants with a capacity of less than 10 MW is closed to foreign ownership. Currently, foreign investors may own up to 95% of power plants with generating capacities greater than 10 MW. The revised regulations will allow foreign investors to own up to 100% of geothermal power plants, with generating capacities greater than 10 MW and up to 67% of geothermal power plants with generating capacities of less than 10 MW.

In late 2016, the Indonesian government attempted to bring the national electricity provision with lower cost and minimized subsidies. In February 2017, the MEMR issued two regulations: No. 10/2017, which regulates the key terms of PPAs and No. 12/2017, which regulates the utilization of renewable energy for the provision of electricity. However, in August 2017, MEMR regulation No. 10/2017 was amended by the regulation MEMR No 49/2017, and regulation MEMR No. 12/2017 was replaced by regulation MEMR No. 50/2017.

Under MEMR No. 50/2017, the tariff policy for geothermal PPAs is mainly determined based on the location of the relevant power plant. For geothermal projects located in Java, Sumatera, Bali and certain other regions that have a local electricity generation cost (the “Local BPP”) below or equal to the national average electricity generation cost (the “National BPP”), the tariff will be based on rates negotiated by the developer and PLN.

For geothermal projects located in regions with a Local BPP that is higher than the National BPP, the ceiling tariff is set to the Local BPP.

In addition to project development, we are also pursuing various supply opportunities in Southeast Asia, including several optimization projects.

China

In **China**, where we recently supplied our equipment to one of our clients’ geothermal projects, the National Energy Administration adopted the 13th Renewable Energy Development Five Year Plan. The plan was adopted in December 2016 and establishes targets for renewable energy deployment until 2020. Key objectives under the plan include, among others, to increase the share of non-fossil fuel energy in total primary energy consumption to 15% by 2020 and to 20% by 2030, and to increase installed renewable power capacity to 680 GW by 2020.

East Africa

In East Africa the geothermal potential along the Rift Valley is estimated at several thousand MW. The different countries along the Rift Valley are at different stages of development of their respective geothermal potentials.

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In **Kenya**, there are already several geothermal power plants, including the only geothermal IPP in Africa, our 139 MW Olkaria III complex. The Kenyan government has identified the country's untapped geothermal potential as the most suitable indigenous source of electricity and it aspires to reach 5 GW of geothermal power generation by 2030. To attain this goal, GDC was formed to fast track the development of geothermal resources in Kenya. We have a 51% interest in a consortium that signed a PPA for a 35 MW geothermal power plant in the Menengai area.

The Kenyan government is aiming to reach 22.7GW of power generating capacity by 2033, under the Least-Cost Power Development Plan 2013-33 with a target of 42% of such capacity generated from renewable energy sources (including large hydro but excluding solar).

In December 2012, FITs for various technologies were reviewed and the process of negotiating PPAs in Kenya streamlined. Geothermal projects subject to this regime have priority grid access at the cost of the developer. Geothermal projects from 35 MW to 70 MW have a USD $0.088 per kWh (up to 500 MW) FIT.

In 2015, the Departmental Committee of Finance, Planning, and Trade amended the Income Tax Act in view of the 2015 Finance Bill. The amendments include maintaining the enhanced investment deduction of 150% under section 17B and extending the period of deduction of tax losses to over 10 years.

The governments of **Djibouti, Ethiopia, Eritrea, Tanzania, Uganda, Rwanda** and **Zambia** are exploring ways to develop geothermal resources in their countries, mostly through the help of international development organizations such as the World Bank.

In **Ethiopia**, the new Geothermal Law Proclamation 981 became effective in 2016, and supporting regulations are under consideration. We hold rights for four concessions in Ethiopia. We are currently negotiating a power purchase agreement with the local government and we have started initial exploration studies on the secured concessions.

In January 2014, energy ministers and delegates from 19 countries committed to the creation of the Africa Clean Energy Corridor Initiative (Corridor), at a meeting in Abu Dhabi convened by the International Renewable Energy Agency. The Corridor will boost the deployment of renewable energy and aim to help meet Africa’s rising energy demand with clean, indigenous, cost-effective power from sources including hydro, geothermal, biomass, wind and solar.

Other opportunities

Recovered Energy Generation

In addition to our geothermal power generation activities, we are pursuing recovered energy-based power generation opportunities in North America and the rest of the world. We believe recovered energy-based power generation will ultimately benefit from the efforts to reduce GHG emissions. For example, in the U.S., FERC has expressed its position that one of the goals of new natural gas pipeline design should be to facilitate the efficient, low-cost transportation of fuel through the use of waste heat (recovered energy) from combustion turbines or reciprocating engines that drive station compressors to generate electricity for use at compressor stations or for commercial sale. FERC has, as a matter of policy, requested natural gas pipeline operators filing for a certificate of approval for new pipeline construction or expansion projects to examine "opportunities to enhance efficiencies for any energy consumption processes in the development and operation" of the new pipeline. We have built 22 power plants which generate electricity utilizing "waste heat" from gas turbine-driven compressor stations along interstate natural gas pipelines, from midstream gas processing facilities, and from processing industries in general.

Several states, and to a certain extent, the federal government, have recognized the environmental benefits of recovered energy-based power generation. For example, 18 states currently allow electric utilities to include recovered energy-based power generation in calculating such utilities' compliance with their mandatory or voluntary RPS and/or Energy Efficient Resources Standards. In addition, California modified the Self Generation Incentive Program to allow recovered energy-based power generation to qualify for a per watt incentive.

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In Colorado, Xcel Energy, the largest utility in that state, now offers a $500 per kW incentive for recycled energy projects. This incentive is paid out over 10 years to developers and manufacturers who convert waste heat from stacks and process it into electricity. The tariff details the rates and a methodology for recycled energy projects that wish to take advantage of this incentive.

Recovery of waste heat is also considered "environmentally friendly" in the western Canadian provinces. On November 22, 2015, the Alberta Government released the Clean Leadership Plan that includes (a) phasing out of coal-fired electricity generation by 2030; (b) a commitment to generate 30 percent of Alberta's electricity from renewable sources by 2030; (c) new financing for energy efficiency; and (d) an economy-wide price on carbon pollution. The plan also mandates that Alberta reduce methane emissions from oil and gas operations by 45% by 2025. In 2016, the Canadian government ratified its commitments in the Paris Agreement, which features a commitment to reduce emissions by 30% from 2005 levels by 2030. The federal government has announced that Canadian provinces must have an emission reduction plan in place or be subject to a federal carbon tax in 2018. This comprehensive set of climate policies, once fully implemented, will encourage the development of renewable energy technologies, including waste heat recovery, in Alberta and other provinces. We believe that Europe and other markets worldwide may offer similar opportunities in recovered energy-based power generation.

In summary, the market for the recovery of waste heat converted into electricity exists either when already available electricity is expensive or where the regulatory environment facilitates construction and marketing of power generated from recovered waste heat. However, such projects tend to be smaller than 9 MW and we expect any growth to be relatively slow and geographically scattered.

New activities under our strategic plan

The traditional grid is undergoing a major disruption. The continued decline in Solar PV prices is impacting renewable energy pricing and the growth in intermittent green energy is generating increasing strains on the grid, mainly in the U.S and Europe. The increasing amount of Solar PV power being supplied to the grid can create situations where a significant amount of power plant capacity must be available to ramp up and down to accommodate Solar PV daily output cycles and variations due to atmospheric conditions. The output from Solar PV power plants can change significantly over short periods of time due to environmental conditions like cloud movement and fog burn off and that can cause instability on the electric grid.

As a result, energy management and specifically electricity storage is becoming a key component of the future grid. In parallel, we see movement of C&I and communities toward direct purchases of electricity and an increased focus on reliability of electricity supply.

Energy Storage

Energy storage systems utilize low cost, surplus, available electricity that enables utilities to optimize the operation of the grid and generators to run closer to full capacity for longer periods of time and operate more efficiently and effectively. With the increasing use of wind and solar energy, the need for storage services such as balancing services, frequency regulation, rapid generation ramping, reactive power, black start and movement of energy from times of excess to times of high demand is becoming more important.

The global energy storage market is still developing, with specific applications and geographies leading the overall market. After a record-breaking year in 2015, the energy battery storage industry is continuing to gain momentum globally. More than 1.6 GW of new deployments (approximately $2.0 billion) were announced worldwide in 2015. Various diversified battery storage technologies have been developed and deployed. According to GTM, total deployed MW in 2016 and 2017 represent continued growth of above 25% per year and forecasts for 2018 and beyond expect greater growth to be achieved as energy storage becomes cheaper and its technologies and markets more mature.

Much of the BESS activity is focused on energy storage for the grid and ancillary services. Behind the meter deployments are growing fast to enable customers to increase savings from demand charge reductions and create revenues through active market participation (demand response programs). Also, grids and utilities are undergoing significant changes such as grid aging, grid congestion, coal retirement, implementation of carbon reduction rules and increasing renewable energy and intermittent energy penetration. BESS delivers many benefits to grids and end users (behind the customer meter, as well as to micro-grids). Real-time balancing services can reactively increase stability and reliability on the grid to offset renewables inherent flexibility, to store energy now to be used later and to promote business resiliency, power quality and physically distributed benefits for all segments of the grid or the end customer.

According to Navigant research, BESS continues to be one of the fastest growing segments of the broader energy industry, set to reach an overall installed power capacity of 143.7 GW and a cumulative global market size of $162.3 billion in the next 10-year period. This represents a CAGR of approximately 30% over the 10-year period in both in-front-of-the meter grid connected and behind-the-meter C&I deployments.

According to a GTM report from December 2016, the U.S. behind-the-meter energy storage market today is small, with combined residential and non-residential deployments in 2015 accounting for only 15% of installed capacity in MW terms. By 2021, however, the behind-the-meter segment is expected to account for half of the annual U.S. market, driven by many factors including improved system economics, net-energy metering reform, changes to utility rate structures, increasing viability of demand-charge management for non-residential customers, and increased interest in reliability and resiliency. GTM is expecting total installations of more than 4 GW through 2021 in the U.S. These trends in the U.S. market are expected to be experienced in other leading global markets in Europe and Asia.

We plan to use our Viridity platform and services to expand our market presence in the energy storage market and further develop our VPower™ software platform to be utilized in optimizing and generating revenues from demand response including ownership and supply of BESS systems. We expect that the eco system we have created, combining our Viridity business's capabilities with our global presence, experience in technology and system integration, EPC capabilities, flexible business models and reputation and experience in the geothermal and recovered energy sectors, will enable us to expand into this growing sector.

C&I

The C&I sector is shifting from centralized electricity generation systems to distributed resources supported by emerging models of direct PPAs with renewable power plants, on-site deployments, and customized solutions for energy management. Participants in the C&I sector are motivated to purchase renewable energy to reduce costs and diversify their energy supply, to lock in long-term energy price stability and carbon footprint reductions, to achieve renewable energy targets and to demonstrate leadership, innovation, and competitive first mover advantages. We see C&I customers as a natural expansion of our customer base from regulated utilities to medium and large C&I customers desiring to contract for renewable energy.

The advances in electricity storage technology together with high period demand charges, demand response programs, concern over electricity supply reliability and more aggressive goals for renewable energy content than those of centralized electricity suppliers are all factors that have supported the growth of the C&I market. The need for technical customized solutions to meet these varied C&I needs fits well with our Viridity business and our experience in providing customized geothermal and REG solutions to various customers around the world.

Solar PV

The market for Solar PV power grew significantly in recent years, driven by a combination of favorable government policies and a decline in equipment prices. We are monitoring market drivers with the potential to develop Solar PV power plants in locations where we can offer competitively priced power generation. Our focus currently is in installing Solar PV systems in some of our operating geothermal power plants to reduce internal consumption loads. We are planning to install the first system in Tungsten Mountain. In addition, we are looking for hybrid projects that involve intermittent power (such as Solar PV) and energy storage.

Competitive Strengths

Competitive Assets. We believe our assets are competitive for the following reasons:

Contracted Generation. All of the electricity generated by our geothermal power plants is currently sold pursuant to long-term PPAs with an average remaining life of approximately 18 years.

Baseload Generation. All of our geothermal power plants supply all or a part of the baseload capacity of the electric system in their respective markets. This means they supply electric power on an around-the-clock basis. This provides us with a competitive advantage over other renewable energy sources, such as wind power, solar power or hydro-electric power (to the extent dependent on precipitation), which cannot provide baseload capacity because of their intermittent nature. It remains to be seen whether developments in the energy storage markets will erode this competitive advantage.

Ancillary Services. Geothermal power plants positively impact electrical grid stability and provide valuable ancillary services. Because of the baseload nature of their output, they have high transmission utilization efficiency, provide capacity, provide grid inertia and reduce the need for ancillary services such as voltage regulation, reserves and flexible capacity. Other intermittent renewables create integration costs, representing a significant value proposition for geothermal energy.

Competitive Pricing. Geothermal power plants, while site specific, are economically feasible in many locations, and the electricity they generate is generally price competitive under existing economic conditions and existing tax and regulatory regimes compared to electricity generated from fossil fuels or other renewable sources in many places around the world. Geothermal energy is recognized as one of the lower cost sources of energy from a LCOE perspective.

Ability to Finance Our Activities from Internally Generated Cash Flow. The cash flow generated by our portfolio of operating geothermal and REG power plants provides us with a robust and predictable base for certain exploration, development, and construction activities. We plan to evaluate various alternatives for financing the expansion of our business as we further develop and implement our new strategic plan.

Growing Legislative Demand for Environmentally-Friendly Renewable Resource Assets. Most of our currently operating power plants produce electricity from geothermal energy sources. The clean and sustainable characteristics of geothermal energy give us a competitive advantage over fossil fuel-based electricity generation as countries increasingly seek to balance environmental concerns with demands for reliable sources of electricity.

High Efficiency from Vertical Integration. Unlike our competitors in the geothermal industry, we are a fully integrated geothermal equipment, services, and power provider. We design, develop, and manufacture equipment that we use in our geothermal and REG power plants. Our intimate knowledge of the equipment that we use in our operations allows us to operate and maintain our power plants efficiently and to respond to operational issues in a timely and cost-efficient manner. Moreover, given the efficient communication among our subsidiaries that design and manufacture the products we use in our operations and our subsidiaries that own and operate our power plants, we are able to quickly and cost effectively identify and repair mechanical issues and to have technical assistance and replacement parts available to us as and when needed.

Exploration and Drilling Capabilities. We have in-house capabilities to explore and develop geothermal resources and have established a drilling operation that currently owns seven drilling rigs. We employ an experienced resource group that includes engineers, geologists, and drillers, which executes our exploration and drilling plans for projects that we develop.

Highly Experienced Management Team. We have a highly qualified senior management team with extensive experience in the geothermal power sector.

Technological Innovation. We have 77 U.S. patents in force (and have approximately 9 U.S. patents pending) relating to various processes and renewable resource technologies. All of our patents are internally developed. Our ability to draw upon internal resources from various disciplines related to the geothermal power sector, such as geological expertise relating to reservoir management, and equipment engineering relating to power units, allows us to be innovative in creating new technologies and technological solutions.

Limited Exposure to Fuel Price Risk. A geothermal power plant does not need to purchase fuel (such as coal, natural gas, or fuel oil) in order to generate electricity. Thus, once the geothermal reservoir has been identified and estimated to be sufficient for use in a geothermal power plant, the drilling of wells is complete, and the plant has a PPA, the plant is not exposed to fuel price or fuel delivery risk apart from the impact fuel prices may have on the price at which we sell power under PPAs that are based on the relevant power purchaser's avoided costs.

Although we are confident in our competitive position in light of the strengths described above, we face various challenges in the course of our business operations, including as a result of the risks described in Item 1A — "Risk Factors" below, the trends and uncertainties discussed in "Trends and Uncertainties" under Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" below, and the competition we face in our different business segments described under "Competition" below.

Business Strategy

Our strategy is to continue building a geographically balanced portfolio of geothermal and recovered energy assets, and to continue to be a leader in the geothermal energy market with the objective of becoming a leading global provider of renewable energy. Since 2015, we have implemented a number of the elements of a new multi-year strategic plan. We expect the plan to evolve over time in response to market conditions and other factors. We intend to implement this strategy through:

- *Development and Construction of New Geothermal Power Plants* — continuously seeking out commercially exploitable geothermal resources, developing and constructing new geothermal power plants and entering into long-term PPAs providing stable cash flows in jurisdictions where the regulatory, tax and business environments encourage or provide incentives for such development.

- *Expanding our Geographical Reach* — increasing our business development activities in an effort to grow our business in the global markets in both business segments. While we continue to evaluate global opportunities, we currently see Turkey, New Zealand, Chile, Kenya, Honduras, China, Indonesia and Ethiopia as very attractive markets for us. We are actively looking at ways to expand our presence in those countries.

- *Acquisition of New Assets* — expanding and accelerating growth through acquisition activities globally, aiming to acquire from third parties additional geothermal assets, such as our recent announcement that we signed an agreement to acquire U.S. Geothermal Inc., which owns approximately 38 MW of operating power plants, and companies and assets that we expect to expedite our entry into the storage and C&I markets, such as our March 2017 acquisition of substantially all of the assets that comprise our Viridity business today.

- *Manufacturing and Providing Products and EPC Services Related to Renewable Energy* — designing, manufacturing and contracting power plants for our own use and selling to third parties power units and other generation equipment for geothermal and recovered energy-based electricity generation.

- *Expanding into New Technologies* — leveraging our technological capabilities over a variety of renewable energy platforms, including solar power generation and energy storage. Initially, however, we expect that our primary focus will be on expanding our core geothermal competencies to provide high efficiency solutions for high enthalpy applications by utilizing our binary enhanced cycle and technology, as well as, expanding into steam geothermal generation equipment and facilities. We may acquire companies with integration and technological capabilities we do not currently have, or develop new technology ourselves, where we can effectively leverage our expertise to implement this part of our strategic plan.

- *Expand our Customer Base* — evaluating a number of strategies for expanding our customer base to the C&I market. In the near term, however, we expect that a majority of our revenues will continue to be generated as they now are, with our traditional electrical utility customer base for the Electricity segment.

- *Increasing Output from Our Existing Power Plants* — increasing output from our existing geothermal power plants by adding additional generating capacity, upgrading plant technology, and improving geothermal reservoir operations, including improving methods of heat source supply and delivery.

- *Cost Saving by Increasing Efficiencies* — increasing efficiencies in our operating power plants and manufacturing facility including procurement by adding new technologies, restructuring of management control, automating part of our manufacturing work and centralizing our operating power plants.

- *Technological Expertise* — investing in research and development of renewable energy technologies and leveraging our technological expertise to continuously improve power plant components, reduce operations and maintenance costs, develop competitive and environmentally friendly products for electricity generation and target new service opportunities.

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Recent Developments

The most significant recent developments in our company and business are described below.

On January 24, 2018, we announced that we entered into a definitive agreement to acquire U.S. Geothermal Inc. (NYSE American: HTM), a renewable energy company focused on the development, production and sale of electricity from geothermal energy. Under the terms of the merger agreement, holders of U.S. Geothermal common stock will receive $5.45 per share in cash. On a fully diluted basis, including payment to U.S. Geothermal's option holders, we expect to pay total consideration of approximately $109.9 million from our corporate funds. The closing of the merger is subject to customary conditions, including receipt of regulatory approvals and approval by holders of a majority of the outstanding shares of US Geothermal's common stock. The transaction is expected to close in the second quarter of 2018.

U.S. Geothermal is currently operating geothermal power projects at Neal Hot Springs, Oregon, San Emidio, Nevada and Raft River, Idaho for a total designed net output of 45 MW that currently generate approximately 38 MW net. In addition, U.S. Geothermal is developing additional projects at the Geysers, California; a second phase project at San Emidio, Nevada; at Crescent Valley, Nevada; and the El Ceibillo project located near Guatemala City, Guatemala.

On December 13, 2017, we announced that the 24 MW Tungsten Mountain geothermal power plant located in Churchill County, Nevada, commenced commercial operation on December 1, 2017. The Tungsten Mountain power plant will sell its power under the 26-year PPA, dated as of October 20, 2016, between our wholly owned subsidiary ONGP, LLC and SCPPA (ONGP Portfolio PPA), which was announced in June 2017. SCPPA resells the entire output of the plant to LADWP. The power plant is expected to generate approximately $15 million in average annual revenue. The Tungsten Mountain geothermal power plant utilizes our latest turbine design and contains the largest OEC ever installed. The new and innovative turbine design will increase the OEC's efficiency, capacity and availability.

On December 13, 2017, we announced that we signed an approximately $50 million EPC contract, with TOP ENERGY Ltd for the Ngawha extension geothermal project located in Ngawha, New Zealand. The project is expected to be completed in the first quarter of 2021. Under the EPC contract, we will provide our air-cooled OEC for the Ngawha extension project. This is the third EPC contract Ormat has signed with TOP ENERGY Ltd. The first was for the Ngawha I power plant in 1998 and the second for the Ngawha II power plant in 2008.

On October 10, 2017, we announced that the second unit of the Sarulla geothermal power plant located in the North Sumatra region of Indonesia, one of the world's largest geothermal power plants, commenced commercial operation. The Sarulla power plant includes three units of approximately 110 MW each, utilizing both steam and brine extracted from the geothermal field to increase the power plant's efficiency. The first unit of the power plant commenced commercial operation on March 17, 2017 and we expect the third unit to commence commercial operation in 2018. The Sarulla power plant is operated by Sarulla Operations Ltd. (SOL), a consortium consisting of Medco Energi Internasional Tbk, Inpex Corporation, Itochu Corporation, Kyushu Electric Power Co. Inc., and our subsidiary that holds a 12.75% equity interest in SOL.

On September 26, 2017, we announced that the 35 MW Platanares geothermal project in Honduras commenced commercial operation. We had previously signed a BOT contract for the Platanares geothermal project in Honduras with ELCOSA, a privately-owned Honduran energy company, for 15 years from COD. The Platanares power plant sells its power under a 30-year PPA with ENEE. We hold a portion of the land on which the power plant is located through a lease from a local municipality. Because the term of the lease exceeds the term in office of the relevant municipal government, the lease remains subject to the additional approval of the Honduran Congress in order to be fully valid. We have commenced the necessary steps to obtain such approval but the current elections in Honduras may result in a delay in obtaining such approval. The project is expected to generate average annual revenue of approximately $33 million.

On July 26, 2017, we announced that ORIX closed its acquisition of approximately 11 million shares of our common stock, representing an approximately 22% ownership stake in the Company, from FIMI ENRG Limited Partnership, FIMI ENRG, L.P., Bronicki Investments, Ltd. and certain senior members of our management team pursuant to a stock purchase agreement entered into by ORIX and the selling stockholders on May 4, 2017. In connection with the acquisition, on May 4, 2017, we entered into certain related agreements with ORIX, including a governance agreement (Governance Agreement), a commercial cooperation agreement (CCA) and a registration rights agreement (RRA), following the unanimous recommendation of a special committee of our Board that was formed to evaluate and negotiate the stockholder arrangements proposed by ORIX, and following approval by the full Board. The foregoing agreements between us and ORIX became effective on July 26, 2017.

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Under the Governance Agreement, ORIX has the right to designate three persons to our Board, which was expanded to nine directors, and propose a fourth person to be mutually agreed by the Company and ORIX to serve as a new independent director on our Board. In addition, for so long as ORIX is entitled to Board representation pursuant to the Governance Agreement, ORIX will be subject to certain customary standstill restrictions, including an effective 25% cap on its voting rights. Pursuant to the RRA, ORIX also has certain customary registration rights with respect to the shares of our common stock that it owns.

Under the CCA, we have exclusive rights to develop, own, operate and provide equipment for ORIX geothermal energy projects in all markets outside of Japan. In addition, we have certain rights to serve as technical partner and co-invest in ORIX geothermal energy projects in Japan. ORIX will also assist us in obtaining project financing for our geothermal projects from a variety of leading providers of renewable energy debt financing with which ORIX has relationships in Asia and around the world.

On June 1, 2017, we announced that SCPPA received the final necessary approval from the City of Los Angeles that enabled SCPPA to execute the ONGP Portfolio PPA. Under the ONGP Portfolio PPA, SCPPA will purchase 150 MW of power generated by a portfolio of our new and existing geothermal power plants. Energy deliveries under the ONGP Portfolio PPA started in the fourth quarter of 2017 and the entire portfolio of geothermal power plants is expected to be online by the end of 2022. The ONGP Portfolio PPA contract capacity is 150 MW, with a minimum delivery requirement of 135 MW and a permitted maximum delivery of 185 MW. The ONGP Portfolio PPA is for a term of approximately 26 years, expiring in December 31, 2043, and has a fixed price of $75.50 per MWh with no escalation.

The ONGP Portfolio PPA covers nine of our primary geothermal power plants, including new projects currently under construction or development, as well as existing geothermal power plants that will commence energy deliveries to SCPPA once their current PPAs terminate. The ONGP Portfolio PPA also covers sixteen secondary facilities that could be used to replace or supplement the primary facilities.

On March 15, 2017, we announced that we completed the acquisition of our Viridity business. At closing, we paid initial consideration of $35.3 million. Additional contingent consideration may be payable upon the achievement of certain performance milestones measured at the end of fiscal year 2020. This transaction marked our entry into the growing energy storage and demand response markets, with an established North American presence.

In February 2017, we began construction to expand the Olkaria III complex in Kenya by an additional 10 MW and increase the complex’s generating capacity to up to 150 MW during 2018.

Operations of our Electricity Segment

How We Own Our Power Plants. We customarily establish a separate subsidiary to own interests in each of our power plants. This ensures that the power plant, and the revenues generated by it, will be the only source for repaying indebtedness, if any, incurred to finance the construction or the acquisition (or to refinance the construction or acquisition) of the relevant power plant. If we do not own all of the interest in a power plant, we enter into a shareholders’ agreement or a partnership agreement that governs the management of the specific subsidiary and our relationship with our partner in connection with the specific power plant. Our ability to transfer or sell our interests in certain power plants may be restricted by certain purchase options or rights of first refusal in favor of our power plant partners or the power plant's power purchasers and/or certain change of control and assignment restrictions in the underlying power plant and financing documents. All of our domestic geothermal and REG power plants are Qualifying Facilities under the PURPA and are eligible for regulatory exemptions from most provisions of the FPA and certain state laws and regulations.

How We Explore and Evaluate Geothermal Resources. Since 2006, we have expanded our exploration activities, initially in the U.S. and in the last few years with an increasing focus internationally. It normally takes two to three years from the time we start active exploration of a particular geothermal resource to the time we have an operating production well, assuming we conclude the resource is commercially viable and determine to pursue its development. Exploration activities generally involve the phases described below.

Initial Evaluation. Identifying and evaluating potential geothermal resources by sampling and studying new areas combined with information available from public and private sources. We generally adhere to the following process, although our process can vary from site to site depending on geological circumstances and prior evaluation:

- We evaluate historic, geologic and geothermal information available from public and private databases, including geothermal, mining, petroleum and academic sources.

- We visit sites, sampling fluids for chemistry if necessary, to evaluate geologic conditions.

- We evaluate available data, and rank prospects in a database according to estimated size and perceived risk. For example, pre-drilled sites with extensive data are considered lower risk than "green field" sites. Both prospect types are considered critical for our continued growth.

- We generally create a digital, spatial geographic information systems (GIS) database and 3D geologic model containing all pertinent information, including thermal water temperature gradients derived from historic drilling, geologic mapping information (e.g., formations, structure, alteration, and topography), and any available archival information about the geophysical properties of the potential resource.

- We assess other relevant information, such as infrastructure (e.g., roads and electric transmission lines), natural features (e.g., springs and lakes), and man-made features (e.g., old mines and wells).

Our initial evaluation is usually conducted by our own staff, although we might engage outside service providers for some tasks from time to time. The costs associated with an initial evaluation vary from site to site, based on various factors, including the acreage involved and the costs, if any, of obtaining information from private databases or other sources. On average, our expenses for an initial evaluation range from approximately $10,000 to $50,000 including travel, chemical analyses, and data acquisition.

If we conclude, based on the information considered in the initial evaluation, that the geothermal resource could support a commercially viable power plant, taking into account various factors described below, we proceed to land rights acquisition.

Land Acquisition. Acquiring land rights to any geothermal resources our initial evaluation indicates could potentially support a commercially viable power plant, taking into account various factors. For domestic power plants, we either lease or own the sites on which our power plants are located. For our foreign power plants, our lease rights for the power plant site are generally contained in the terms of a concession agreement or other contract with the host government or an agency thereof. In certain cases, we also enter into one or more geothermal resource leases (or subleases) or a concession or an option agreement or other agreement granting us the exclusive right to extract geothermal resources from specified areas of land, with the owners (or sublessors) of such land. In some cases, we first obtain the exploration license and once certain investment requirements are met, we can obtain the geothermal exploitation rights. This usually gives us the right to explore, develop, operate, and maintain the geothermal field, including, among other things, the right to drill wells (and if there are existing wells in the area, to alter them) and build pipelines for transmitting geothermal fluid. In certain cases, the holder of rights in the geothermal resource is a governmental entity and in other cases a private entity. Usually the duration of the lease (or sublease) and concession agreement corresponds to the duration of the relevant PPA, if any. In certain other cases, we own the land where the geothermal resource is located, in which case there are no restrictions on its utilization. Leasehold interests in federal land in the U.S. are regulated by the BLM and the Minerals Management Service. These agencies have rules governing the geothermal leasing process as discussed below under "Description of Our Leases and Lands".

For most of our current exploration sites in the U.S., we acquire rights to use the geothermal resource through land leases with the BLM, with various states, or through private leases. Under these leases, we typically pay an up-front non-refundable bonus payment, which is a component of the competitive lease process. In addition, we undertake to pay nominal, fixed annual rent payments for the period from the commencement of the lease through the completion of construction. Upon the commencement of power generation, we begin to pay to the lessors long-term royalty payments based on the use of the geothermal resources as defined in the respective agreements. These payments are contingent on the power plant's revenues. A summary of our typical lease terms is provided below under "Description of our Leases and Lands".

The up-front bonus and royalty payments vary from site to site and are based on, among other things, current market conditions.

Surveys. Conducting geological, geochemical, and/or geophysical surveys on the sites acquired. Following the acquisition of land rights for a potential geothermal resource, we conduct additional surface water analyses, soil surveys, and geologic mapping to determine proximity to possible heat flow anomalies and up-flow/permeable zones. We augment our digital database with the results of those analyses and create conceptual and digital geologic models to describe geothermal system controls. We then initiate a suite of geophysical surveys (e.g., gravity, magnetics, resistivity, magnetotellurics, reflection seismic, LiDAR, and spectral surveys) to assess surface and sub-surface structure (e.g., faults and fractures) and improve the geologic model of fluid-flow conduits and permeability controls. All pertinent geological and geophysical data are used to create three-dimensional geologic models to identify drill locations. These surveys are conducted incrementally considering relative impact and cost, and the geologic model is updated continuously.

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We make a further determination of the commercial viability of the geothermal resource based on the results of this process, particularly the results of the geochemical surveys estimating temperature and the overall geologic model, including potential resource size. If the results from the geochemical surveys are poor (i.e., low derived resource temperatures or poor permeability) or the geologic model indicates small or deep resource, we re-evaluate the commercial viability of the geothermal resource and may not proceed to exploratory drilling. We generally only move forward with those sites that we believe have a high probability of successful development.

Exploratory Drilling. Drilling one or more exploratory wells on the high priority, relatively low risk sites to confirm and/or define the geothermal resource. If we proceed to exploratory drilling, we generally use outside contractors to create access roads to drilling sites and related activities. We have continued efforts to reduce exploration costs and therefore, after obtaining drilling permits, we generally drill temperature gradient holes and/or core holes that are lower cost than slim holes (used in the past) using either our own drilling equipment, whenever possible, or outside contractors. If the obtained data supports a conclusion that the geothermal resource can support a commercially viable power plant, it will be used as an observation well to monitor and define the geothermal resource. If the core hole indicates low temperatures or does not support the geologic model of anticipated permeability, it may be plugged, and the area reclaimed. In undrilled sites, we typically step up from shallow (500-1000 feet) to deeper (2000-4000 feet) wells as confidence improves. Following proven temperature in core wells, we typically move to slim and/or full- size wells to quantify permeability.

Each year we determine and approve an exploration budget for the entire exploration activity in such year. We prioritize budget allocation between the various geothermal sites based on commercial and geological factors. The costs we incur for exploratory drilling vary from site to site based on various factors, including the accessibility of the drill site, the geology of the site, and the depth of the resource. However, on average, exploration costs, prior to drilling of a full-size well are approximately $1.0 million to $3.0 million for each site, not including land acquisition. However, we only reach such spending levels for sites that proved to be successful in the early stages of exploration.

At various points during our exploration activities, we re-assess whether the geothermal resource involved will support a commercially viable power plant based on information available at that time. Among other things, we consider the following factors:

- New data and interpretations obtained concerning the geothermal resource as our exploration activities proceed, and particularly the expected MW capacity power plant the resource can be expected to support. The MW capacity can be estimated using analogous systems and/or quantitative heat in place estimates until results from drilling and flow tests quantify temperature, permeability, and resulting resource size.

- Current and expected market conditions and rates for contracted and merchant electric power in the market(s) to be serviced.

- Availability of transmission capacity.
- Anticipated costs associated with further exploration activities and the relative risk of failure.
- Anticipated costs for design and construction of a power plant at the site.
- Anticipated costs for operation of a power plant at the site, particularly taking into account the ability to share certain types of costs (such as control rooms) with one or more other power plants that are, or are expected to be, operating near the site.

If we conclude that the geothermal resource involved will support a commercially viable power plant, we proceed to constructing a power plant at the site.

How We Construct Our Power Plants. The principal phases involved in constructing one of our geothermal power plants are as follows:

- Drilling production and injection wells.
- Designing the well field, power plant, equipment, controls, and transmission facilities.

- Obtaining any required permits, electrical interconnection and transmission agreements.

- Manufacturing (or in the case of equipment we do not manufacture ourselves, purchasing) the equipment required for the power plant.

- Assembling and constructing the well field, power plant, transmission facilities, and related facilities.

In recent years, it takes approximately three years from the time we drill a production well, until the power plant becomes operational.

Drilling Production and Injection Wells. We consider completing the drilling of the first production well to be the beginning of our construction phase for a power plant. However, this is not always sufficient for a full release for construction. The number of production wells varies from plant to plant depending on, among other things, the geothermal resource, the projected capacity of the power plant, the power generation equipment to be used and the way geothermal fluids will be re-injected through injection wells to maintain the geothermal resource and surface conditions. We generally drill the wells ourselves although in some cases we use outside contractors.

The cost for each production and injection well varies depending on, among other things, the depth and size of the well and market conditions affecting the supply and demand for drilling equipment, labor and operators. In the last five years, our typical cost for each production and injection well is approximately $3.3 million with a range of $1.0 million to $13.0 million.

Design. We use our own employees to design the well field and the power plant, including equipment that we manufacture and that will be needed for the power plant. The designs vary based on various factors, including local laws, required permits, the geothermal resource, the expected capacity of the power plant and the way geothermal fluids will be re-injected to maintain the geothermal resource and surface conditions.

Permits. We use our own employees and outside consultants to obtain any required permits and licenses for our power plants that are not already covered by the terms of our site leases. The permits and licenses required vary from site to site, and are described below under “Environmental Permits”.

Manufacturing. Generally, we manufacture most of the power generating unit equipment we use at our power plants. Multiple sources of supply are generally available for all other equipment we do not manufacture.

Construction. We use our own employees to manage the construction work. For site grading, civil, mechanical, and electrical work we use subcontractors.

During fiscal year 2017, in the Electricity segment, we focused on the commencement of operations at Platanares power plant in Honduras and Tungsten Mountain in Nevada. We began with construction of the Olkaria III plant expansion in Kenya and enhancement work in some of our operating power plants. During fiscal year 2016, we focused on the commencement of operations at Olkaria III plant 4. During fiscal year 2015, we focused on the commencement of operations at the McGinness Hills phase 2 and the Don A. Campbell phase 2 power plants. We continued with construction of Olkaria III plant 4.

When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operation. As a result, during fiscal year 2017 we discontinued exploration activities at four prospective sites: the Ungaran region in Indonesia, Glass Buttes - Midnight Point in Oregon and Tuscarora - phase 2 and Don A. Campbell - phase 3, in Nevada. During fiscal year 2016, we discontinued exploration activities at three future prospective sites, in the Kula region in Hawaii and the Aqua Quieta and Sollipulli regions in Chile. During fiscal year 2015, we discontinued exploration and development activities at ten future prospects, including Kona and Ulupalakua (Maui) in Hawaii, Warm Springs Tribe and Newberry - Twilight in Oregon, Whirlwind Valley in Utah, Argenta, Hycroft and South Jersey in Nevada and Mariman and Quinohuen in Chile.

After conducting exploratory studies at those sites, we concluded that the respective geothermal resources would not support commercial operations. Costs associated with exploration activities at these sites were expensed accordingly (see “Write-off of Unsuccessful Exploration Activities” under Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations”).

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We added to our exploration inventory two prospective sites in 2017 and ten prospective sites in each of the years ended December 31, 2016 and 2015.

How We Operate and Maintain Our Power Plants. In the U.S., our wholly owned subsidiary, Ormat Nevada, usually acts as the operator of our power plants pursuant to the terms of an operation and maintenance agreement. Operation and maintenance of our foreign projects are generally provided by our subsidiary that owns the relevant project. Our operations and maintenance practices are designed to minimize operating costs without compromising safety or environmental standards while maximizing plant flexibility and maintaining high reliability. Our operations and maintenance practices for geothermal power plants seek to preserve the sustainable characteristics of the geothermal resources we use to produce electricity and maintain steady-state operations within the constraints of those resources reflected in our relevant geologic and hydrologic studies. Our approach to plant management emphasizes the operational autonomy of our individual plant or complex managers and staff to identify and resolve operations and maintenance issues at their respective power plants; however, each power plant or complex draws upon our available collective resources and experience, and that of our subsidiaries. We have organized our operations such that inventories, maintenance, backup, and other operational functions are pooled within each power plant complex and provided by one operation and maintenance provider. This approach enables us to realize cost savings and enhances our ability to meet our power plant availability goals.

Safety is a key area of concern to us. We believe that the most efficient and profitable performance of our power plants can only be accomplished within a safe working environment for our employees. Our compensation and incentive program includes safety as a factor in evaluating our employees, and we have a well-developed reporting system to track safety and environmental incidents, if any, at our power plants.

How We Sell Electricity. In the U.S., the purchasers of power from our power plants are typically investor-owned electric utility companies or electric cooperatives including public owned utilities. Outside of the U.S., the purchaser is either a state-owned utility or a privately-owned entity and we typically operate our facilities pursuant to rights granted to us by a governmental agency pursuant to a concession agreement. In each case, we enter into long-term contracts (typically, PPAs) for the sale of electricity or the conversion of geothermal resources into electricity. Although previously our power plants’ revenues under a PPA generally consisted of two payments, energy payments and capacity payments, our recent PPAs provide for energy payments only. Energy payments are normally based on a power plant’s electrical output actually delivered to the purchaser measured in kWh, with payment rates either fixed or indexed to the power purchaser’s “avoided” power costs (i.e., the costs the power purchaser would have incurred itself had it produced the power it is purchasing from third parties) or rates that escalate at a predetermined percentage each year. Capacity payments are normally calculated based on the generating capacity or the declared capacity of a power plant available for delivery to the purchaser, regardless of the amount of electrical output actually produced or delivered. In addition, we have six domestic power plants located in California, Nevada and Hawaii that are eligible for capacity bonus payments under the respective PPAs upon reaching certain levels of generation, or subject to a capacity payment reduction if certain levels of generation are not reached.

How We Finance Our Power Plants. Historically we have funded our power plants with different sources of liquidity such as a non-recourse or limited recourse debt, lease financing, tax monetization transactions, internally generated cash, which includes funds from operation, as well as proceeds from loans under corporate credit facilities and the sale of equity interests and other securities. Such leveraged financing permits the development of power plants with a limited amount of equity contributions, but also increases the risk that a reduction in revenues could adversely affect a particular power plant’s ability to meet its debt obligations. Leveraged financing also means that distributions of dividends or other distributions by our power plant subsidiaries to us are contingent on compliance with financial and other covenants contained in the applicable financing documents.

Non-recourse debt or lease financing refers to debt or lease arrangements involving debt repayments or lease payments that are made solely from the power plant’s revenues (rather than our revenues or revenues of any other power plant) and generally are secured by the power plant’s physical assets, major contracts and agreements, cash accounts and, in many cases, our ownership interest in our affiliate that owns that power plant. These forms of financing are referred to as “project financing”. Project financing transactions generally are structured so that all revenues of a power plant are deposited directly with a bank or other financial institution acting as escrow or security deposit agent. These funds are then payable in a specified order of priority set forth in the financing documents to ensure that, to the extent available, they are used to first pay operating expenses, senior debt service (including lease payments) and taxes, and to fund reserve accounts. Thereafter, subject to satisfying DSCR and certain other conditions, available funds may be disbursed for management fees or dividends or, where there are subordinated lenders, for the payment of subordinated debt service.

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In the event of a foreclosure after a default, our affiliate that owns the power plant would only retain an interest in the power plant assets, if any, remaining after all debts and obligations have been paid in full. In addition, incurrence of debt by a power plant may reduce the liquidity of our equity interest in that power plant because the equity interest is typically subject both to a pledge in favor of the power plant's lenders securing the power plant's debt and to transfer and change of control restrictions set forth in the relevant financing agreements.

Limited recourse debt refers to project financing as described above with the addition of our agreement to undertake limited financial support for our affiliate that owns the power plant in the form of certain limited obligations and contingent liabilities. These obligations and contingent liabilities may take the form of guarantees of certain specified obligations, indemnities, capital infusions and agreements to pay certain debt service deficiencies. To the extent we become liable under such guarantees and other agreements in respect of a particular power plant, distributions received by us from other power plants and other sources of cash available to us may be required to be used to satisfy these obligations. Creditors of a project financing of a particular power plant may have direct recourse to us to the extent of these limited recourse obligations.

We have used financing structures to monetize PTCs and depreciation, such as our recent tax equity partnership transaction involving Opal Geo, and an operating lease arrangement for our Puna complex power plants.

We have also used a sale of equity interests in two of our geothermal assets and nine of our REG facilities to fund corporate needs including funding for the construction of new projects. We may use of the same financing structure in the future.

How We Mitigate International Political Risk. We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries, as described below under "Insurance". To date, our political risk insurance policies are with MIGA, a member of the World Bank Group, and Zurich Re, a private insurance and re-insurance company**.** Such insurance policies generally cover, subject to the limitations and restrictions contained therein, 80-90% of our losses resulting from specified governmental actions or responses thereto, such as confiscation, expropriation, riots, the inability to convert local currency into hard currency, and, in certain cases, the breach of agreements. We have obtained such insurance for the Olkaria, Zunil, Amatitlan, Platanares and Sarulla projects.

Description of Our Leases and Lands

We have domestic leases on approximately 320,500 acres of federal, state, and private land in California, Hawaii, Nevada, New Mexico, Utah and Oregon. The approximate breakdown between federal, state and private leases and owned land is as follows:

- 85% of the acreage under our control is leased from the U.S. government, acting mainly through the BLM;
- 11% is leased or subleased from private landowners and/or leaseholders;
- 2% is owned by us; and
- the balance is leased from various states, none of which is currently material.

Each of the leases within each of the categories above has standard terms and requirements, as summarized below. Internationally, our land position includes approximately 122,500 acres, most of which are for geothermal prospects in Honduras.

BLM Geothermal Leases

Certain of our domestic project subsidiaries have entered into geothermal resources leases with the U.S. government, pursuant to which they have obtained the right to conduct their geothermal development and operations on federally-owned land. These leases are made pursuant to the Geothermal Steam Act and the lessor under such leases is the U.S. government, acting through the BLM.

BLM geothermal leases grant the geothermal lessee the right and privilege to drill for, extract, produce, remove, utilize, sell, and dispose of geothermal resources on certain lands, together with the right to build and maintain necessary improvements thereon. The actual ownership of the geothermal resources and other minerals beneath the land is retained in the federal mineral estate. The geothermal lease does not grant to the geothermal lessee the exclusive right to develop the lands, although the geothermal lessee does hold the exclusive right to develop geothermal resources within the lands. The geothermal lessee does not have the right to develop minerals unassociated with geothermal production and cannot prohibit others from developing the minerals present in the lands. The BLM may grant multiple leases for the same lands and, when this occurs, each lessee is under a duty to not unreasonably interfere with the development rights of the other. Because BLM leases do not grant to the geothermal lessee the exclusive right to use the surface of the land, BLM may grant rights to others for activities that do not unreasonably interfere with the geothermal lessee’s uses of the same land; such other activities may include recreational use, off-road vehicles, and/or wind or solar energy developments.

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Certain BLM leases issued before August 8, 2005 include covenants that require the projects to conduct their operations under the lease in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the land. Additionally, certain leases contain additional requirements, some of which concern the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plants or animals, the payment of royalties for timber, and the imposition of certain restrictions on residential development on the leased land.

BLM leases entered into after August 8, 2005 require the geothermal lessee to conduct operations in a manner that minimizes impacts to the land, air, water, to cultural, biological, visual, and other resources, and to other land uses or users. The BLM may require the geothermal lessee to perform special studies or inventories under guidelines prepared by the BLM. The BLM reserves the right to continue existing leases and to authorize future uses upon or in the leased lands, including the approval of easements or rights-of-way. Prior to disturbing the surface of the leased lands, the geothermal lessee must contact the BLM to be apprised of procedures to be followed and modifications or reclamation measures that may be necessary. Subject to BLM approval, geothermal lessees may enter into unit agreements to cooperatively develop a geothermal resource. The BLM reserves the right to specify rates of development and to require the geothermal lessee to commit to a communalization or unitization agreement if a common geothermal resource is at risk of being overdeveloped.

Typical BLM leases issued to geothermal lessees before August 8, 2005 have a primary term of ten years and will renew so long as geothermal resources are being produced or utilized in commercial quantities but cannot exceed a period of forty years after the end of the primary term. If at the end of the forty-year period geothermal steam is still being produced or utilized in commercial quantities and the lands are not needed for other purposes, the geothermal lessee will have a preferential right to renew the lease for a second forty-year term, under terms and conditions as the BLM deems appropriate.

BLM leases issued after August 8, 2005 have a primary term of ten years. If the geothermal lessee does not reach commercial production within the primary term, the BLM may grant two five-year extensions if the geothermal lessee: (i) satisfies certain minimum annual work requirements prescribed by the BLM for that lease, or (ii) makes minimum annual payments. Additionally, if the geothermal lessee is drilling a well for the purposes of commercial production, the primary term (as it may have been extended) may be extended for five years and as long thereafter as steam is being produced and used in commercial quantities (meaning the geothermal lessee either begins producing geothermal resources in commercial quantities or has a well capable of producing geothermal resources in commercial quantities and is making diligent efforts to utilize the resource) for thirty-five years. If, at the end of the extended thirty-five-year term, geothermal steam is still being produced or utilized in commercial quantities and the lands are not needed for other purposes, the geothermal lessee will have a preferential right to renew the lease for fifty-five years, under terms and conditions as the BLM deems appropriate.

For BLM leases issued before August 8, 2005, the geothermal lessee is required to pay an annual rental fee (on a per acre basis), which escalates according to a schedule described therein, until production of geothermal steam in commercial quantities has commenced. After such production has commenced, the geothermal lessee is required to pay royalties (on a monthly basis) on the amount or value of (i) steam, (ii) by-products derived from production, and (iii) commercially de-mineralized water sold or utilized by the project (or reasonably susceptible to such sale or use).

For BLM leases issued after August 8, 2005, (i) a geothermal lessee who has obtained a lease through a non-competitive bidding process will pay an annual rental fee equal to $1.00 per acre for the first ten years and $5.00 per acre each year thereafter; and (ii) a geothermal lessee who has obtained a lease through a competitive process will pay a rental equal to $2.00 per acre for the first year, $3.00 per acre for the second through tenth year and $5.00 per acre each year thereafter. Rental fees paid before the first day of the year for which the rental is owed will be credited towards royalty payments for that year. For BLM leases issued, effective, or pending on August 5, 2005 or thereafter, royalty rates are fixed between 1.0-2.5% of the gross proceeds from the sale of electricity during the first ten years of production under the lease. The royalty rate set by the BLM for geothermal resources produced for the commercial generation of electricity but not sold in an arm’s length transaction is 1.75% for the first ten years of production and 3.5% thereafter. The royalty rate for geothermal resources sold by the geothermal lessee or an affiliate in an arm’s length transaction is 10.0% of the gross proceeds from the arm’s length sale. The BLM may readjust the rental or royalty rates at not less than twenty-year intervals beginning thirty-five years after the date geothermal steam is produced.

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In the event of a default under any BLM lease, or the failure to comply with any of the provisions of the Geothermal Steam Act or regulations issued under the Geothermal Steam Act or the terms or stipulations of the lease, the BLM may, 30 days after notice of default is provided to the relevant project, (i) suspend operations until the requested action is taken, or (ii) cancel the lease.

Private Geothermal Leases

Certain of our domestic project subsidiaries have entered into geothermal resources leases with private parties, pursuant to which they have obtained the right to conduct their geothermal development and operations on privately owned land. In many cases, the lessor under these private geothermal leases owns only the geothermal resource and not the surface of the land.

Typically, the leases grant our project subsidiaries the exclusive right and privilege to drill for, produce, extract, take and remove from the leased land water, brine, steam, steam power, minerals (other than oil), salts, chemicals, gases (other than gases associated with oil), and other products produced or extracted by such project subsidiary. The project subsidiaries are also granted certain non-exclusive rights pertaining to the construction and operation of plants, structures, and facilities on the leased land. Additionally, the project subsidiaries are granted the right to dispose geothermal fluid as well as the right to re-inject into the leased land water, brine, steam, and gases in a well or wells for the purpose of maintaining or restoring pressure in the productive zones beneath the leased land or other land in the vicinity. Because the private geothermal leases do not grant to the lessee the exclusive right to use the surface of the land, the lessor reserves the right to conduct other activities on the leased land in a manner that does not unreasonably interfere with the geothermal lessee’s uses of the same land, which other activities may include agricultural use (farming or grazing), recreational use and hunting, and/or wind or solar energy developments.

The leases provide for a term consisting of a primary term in the range of five to 30 years, depending on the lease, and so long thereafter as lease products are being produced or the project subsidiary is engaged in drilling, extraction, processing, or reworking operations on the leased land.

As consideration under most of our project subsidiaries’ private leases, the project subsidiary must pay to the lessor a certain specified percentage of the value “at the well” (which is not attributable to the enhanced value of electricity generation), gross proceeds, or gross revenues of all lease products produced, saved, and sold on a monthly basis. In certain of our project subsidiaries’ private leases, royalties payable to the lessor by the project subsidiary are based on the gross revenues received by the lessee from the sale or use of the geothermal substances, either from electricity production or the value of the geothermal resource “at the well”.

In addition, pursuant to the leases, the project subsidiary typically agrees to commence drilling, extraction or processing operations on the leased land within the primary term, and to conduct such operations with reasonable diligence until lease products have been found, extracted and processed in quantities deemed “paying quantities” by the project subsidiary, or until further operations would, in such project subsidiary’s judgment, be unprofitable or impracticable. The project subsidiary has the right at any time within the primary term to terminate the lease and surrender the relevant land. If the project subsidiary has not commenced any such operations on said land (or on the unit area, if the lease has been unitized), or terminated the lease within the primary term, the project subsidiary must pay to the lessor, in order to maintain its lease position, annually in advance, a rental fee until operations are commenced on the leased land.

If the project subsidiary fails to pay any installment of royalty or rental when due and if such default continues for a period of fifteen days specified in the lease, for example, after its receipt of written notice thereof from the lessor, then at the option of the lessor, the lease will terminate as to the portion or portions thereof as to which the project subsidiary is in default. If the project subsidiary defaults in the performance of any obligations under the lease, other than a payment default, and if, for a period of 90 days after written notice is given to it by the lessor of such default, the project subsidiary fails to commence and thereafter diligently and in good faith take remedial measures to remedy such default, the lessor may terminate the lease.

We do not regard any property that we lease as material unless and until we begin construction of a power plant on the property, that is, until we drill a production well on the property.

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Description of Our Power Plants

Domestic Operating Power Plants

The following descriptions summarize certain industry metrics for our domestic operating power plants:

Brady Complex

Location	Churchill County, Nevada
Generating Capacity	18 MW
Number of Power Plants	Two (Brady and Desert Peak 2 power plants).
Technology	The Brady complex utilizes binary and flash systems. The complex uses air and water-cooled systems.
Subsurface Improvements	12 production wells and nine injection wells are connected to the plants through a gathering system.
Major Equipment	Three OECs and three steam turbines along with the Balance of Plant equipment.
Age	The Brady power plant commenced commercial operation in 1992 and a new OEC was added in 2004. The Desert Peak 2 power plant commenced commercial operation in 2007.
Land and Mineral Rights	The Brady complex is comprised mainly of BLM leases that are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants in the Brady complex. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases, and the Brady power plant holds rights of way from the BLM and from a private owner that allows access to and from the plant.
Resource Information	The resource temperatures at the Brady and Desert Peak 2 power plants are 270 degrees Fahrenheit and 338 degrees Fahrenheit, respectively.
	The Brady and Desert Peak geothermal systems are located within the Hot Springs Mountains, approximately 60 miles northeast of Reno, Nevada, in northwestern Churchill County.

	The dominant geological feature of the Brady area is a linear north-northeast-trending band of hot ground that extends two miles. The Desert Peak geothermal field is located within the Hot Springs Mountains, which form part of the western boundary of the Carson Sink. The structure is characterized by east-titled fault blocks and north-northeast-trending folds. The geologic structure in the area is dominated by high-angle normal faults of varying displacement.
Resource Cooling	During the last three years the cooling at the Brady power plant has levelled off to a rate of one degree Fahrenheit per year. The temperature decline at the Desert Peak 2 power plant is approximately two degrees Fahrenheit per year.
Sources of Makeup Water	Condensed steam is used for makeup water.
Power Purchaser	The Sierra Pacific Power Company and Nevada Power Company purchase power generated by the Brady power plant and Desert Peak 2 power plant, respectively.
PPA Expiration Date	Brady power plant — 2022. Desert Peak 2 power plant — 2027.
Financing	The prior financing transactions covering the Brady complex have been fully paid off.
Supplemental Information	We are currently in the process of enhancing the Brady power plant. We are replacing its equipment with new OECs, following which we expect the capacity of the complex to increase by 4 MW to approximately 22 MW. Engineering and manufacturing have been completed, and transportation and construction are ongoing. We expect the enhancement to be completed in the first half of 2018.

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Brawley Complex

Location	Imperial County, California
Generating Capacity	13 MW (See supplemental information below)
Number of Power Plants	One
Technology	The Brawley power plant utilizes a water-cooled binary system.
Subsurface Improvements	36 wells have been drilled and are connected to the Brawley power plant through its gathering system. As we improved our knowledge of the geothermal resource, we changed some of the wells from production to injection (and vice versa) and left others idle. Currently, we have 13 wells connected to the production header and 23 wells, connected to the injection header.
Major Equipment	Five OECs together with the Balance of Plant equipment.
Age	The Brawley power plant commenced commercial operation on March 31, 2011.
Land and Mineral Rights	The Brawley area is comprised entirely of private leases. The leases are held by production. The scheduled expiration date for all of these leases is after the end of the expected useful life of the power plant. The plant’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	Brawley production is from deltaic and marine sedimentary sands and sandstones deposited in the subsiding Salton Trough of the Imperial Valley. Based on seismic refraction surveys the total thickness of these sediments in the Brawley area is over 15,000 feet. The shallow production reservoir (from depths of 1,500 to 4,500 feet) that was developed is fed by fractures and matrix permeability and is conductively heated from the underlying fractured reservoir which convectively circulates magmatically heated fluid. Produced fluid salinity ranges from 20,000 to 50,000 ppm, and the moderate scaling and corrosion potential is chemically inhibited. The temperature of the deeper fractured reservoir fluids exceed 525 degrees Fahrenheit, but the fluid is not yet developed because of severe scaling and corrosion potential. The deep reservoir is not dedicated to the Brawley power plant. The average produced fluid resource temperature is 310 degrees Fahrenheit.
Resource Cooling	The temperature of the geothermal resource depends on the mix of operating production wells that we use.

Sources of Makeup Water	Water is provided by the IID.
Power Purchaser	Southern California Edison
PPA Expiration Date	2031.
Financing	Corporate funds and ITC cash grant from the U.S. Treasury.
Supplemental Information	We are currently selling the power generated by the Brawley complex to Southern California Edison under an existing PPA at a capacity level of approximately 8 MW and we are planning to increase this level to 11 MW by the end of 2018 and further thereafter. With a new chemical supply system, we plan to activate several idle wells and we recently drilled a well in eastern Brawley and connected it to the power plant. As a result, we expect to see an increase in generation.

Don A. Campbell Complex

Location	Mineral County, Nevada
Generating Capacity	41 MW
Number of Power Plants	Two (phase 1 and phase 2)
Technology	The Don A. Campbell power plants utilize an air-cooled binary system.
Subsurface Improvements	Nine production wells and five injection wells are connected to the plants.
Material Equipment	Two air-cooled OECs with the Balance of Plant equipment.
Age	The phase 1 power plant commenced commercial operation on January 1, 2014 and the phase 2 power plant commenced commercial operation on September 27, 2015.
Land and Mineral Rights	The Don A. Campbell area is comprised of BLM leases.
	The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Resource Information	The Don A. Campbell geothermal reservoir consists of highly fractured, silicified alluvium over at least two square miles. Production and injection are very shallow with nine pumped production wells (from depths of 1,350 feet to 1,900 feet) and five injection wells (from depths of 649 feet to 2,477 feet), all targeting northwest-dipping fractures. The thermal fluids are thought to be controlled by a combination of conductive heat transfer from deeper bedrock and through mixing of upwelling thermal fluids from a deeper geothermal system also contained in the bedrock. The system is considered blind with no surface expression of thermal features.
	The temperature of the resource is approximately 254 degrees Fahrenheit.
Resource Cooling	Temperature started declining in mid-2016. An injection well was drilled in 2017 and testing is in process to confirm the impact on temperature decline. Injection tests and tracer studies, along with reservoir modeling, will further develop a plan to mitigate temperature decline of the reservoir.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	Two separate PPAs with SCPPA.

PPA Expiration Date	The phase 1 PPA expires in 2034 and the phase 2 PPA expires in 2036
Financing	The phase 1 power plant was financed through our sale of our 4.03% Senior Secured Notes and a cash grant that we received from the U.S. Treasury. The phase 2 power plant was financed using corporate funds and the proceeds of the tax equity transaction involving Opal Geo.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants. In November 2016, Northleaf purchased a 36.75% equity interest in the Don A. Campbell phase 2 power plant, which was initially added to the existing ORPD portfolio and then later contributed to Opal Geo, which is indirectly owned by ORPD, in connection with the tax equity partnership transaction as described below.

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Heber Complex

Location	Heber, Imperial County, California
Generating Capacity	89 MW
Number of Power Plants	Five (Heber 1, Heber 2, Heber South, Gould 1 and Gould 2).
Technology	The Heber 1 plant utilizes a dual flash system and a binary bottoming unit called Gould 1 and the Heber 2, Gould 2 and Heber South plants all utilize binary systems. The complex uses a water cooled system.
Subsurface Improvements	27 production wells and 38 injection wells connected to the plants through a gathering system.
Major Equipment	17 OECs and one steam turbine with the Balance of Plant equipment.
Age	The Heber 1 plant, Heber 2, Heber South, Gould 1 and Gould 2 plants commenced commercial operation in 1985, 1993, 2008, 2006 and 2005, respectively.
Land and Mineral Rights	The Heber complex is comprised mainly of private leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The resource supplying the flash flowing Heber 1 wells averages 341 degrees Fahrenheit. The resource supplying the pumped Heber 2 wells averages 316 degrees Fahrenheit. The Heber complex's production is from deltaic sedimentary sandstones deposited in the subsiding Salton Trough of California's Imperial Valley. Produced fluids rise from near the magmatic heated basement rocks (18,000 feet) via fault/fracture zones to the near surface. Heber 1 wells produce directly from deep (4,000 to 8,000 feet) fracture zones. Heber 2 wells produce from the nearer surface (2,000 to 4,000 feet) matrix permeability sandstones in the horizontal outflow plume fed by the fractures from below and the surrounding ground waters. Scale deposition in the flashing Heber 1 producers is controlled by down hole chemical inhibition supplemented with occasional mechanical cleanouts and acid treatments. There is no scale deposition in the Heber 2 production wells.

Resource Cooling	Average cooling of one degree Fahrenheit per year was observed during the past 20 years of production.
Sources of Makeup Water	Water is provided by condensate and by the IID.
Power Purchaser	One PPA with Southern California Edison and two PPAs with SCPPA.

PPA Expiration Date	Heber 1 — 2025, Heber 2 — 2023, and Heber South — 2031. The output from the Gould 1 and Gould 2 power plants is sold under the PPAs with SCPPA.
Financing	The Heber complex was financed through the sale of OrCal Senior Secured Notes and the proceeds of the transaction involving our subsidiary ORTP described below
Supplemental Information	We are currently in the process of enhancing the Heber 1 power plant. We are planning to convert artesian wells to pumped wells, add a new water cooling unit and replace one of the OECs, following which we expect the capacity of the complex to reach 89 MW. Construction is ongoing and completion of the enhancement is expected in the first quarter of 2018.

Jersey Valley Power Plant

Location	Pershing County, Nevada
Generating Capacity	10 MW
Number of Power Plants	One
Technology	The Jersey Valley power plant utilizes an air cooled binary system.
Subsurface Improvements	Two production wells and four injection wells are connected to the plant through a gathering system. A third production well is not connected to the power plant and will be used in the future as required.
Major Equipment	Two OECs together with the Balance of Plant equipment.
Age	Construction of the power plant was completed at the end of 2010 and the off-taker approved commercial operation under the PPA on August 30, 2011.
Land and Mineral Rights	The Jersey Valley site is comprised of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plant. The power plant's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from leased property and access across leased property are provided under surface rights granted in leases from BLM.
Resource Information	The Jersey Valley geothermal reservoir consists of a small high-permeability area surrounded by a large low-permeability area. The high-permeability area has been defined by wells drilled along an interpreted fault trending west-northwest. Static water levels are artesian; two of the wells along the permeable zone have very high productivities, as indicated by Permeability Index (PI) values exceeding 20 gpm/psi. The average temperature of the resource is 310 degrees Fahrenheit.

Resource Cooling	The rate of cooling was four degrees Fahrenheit in 2015, but we have moderated such cooling by reducing the injection rate in a well near the production wells. To offset the reduction of injection in this well, we diverted more fluid to farther away wells (by increasing injection pressure).
Power Purchaser	Nevada Power Company
PPA Expiration Date	2032

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Financing	The Jersey Valley power plant was financed through the sale of our OFC 2 Senior Secured Notes, corporate funds, an ITC cash grant from the U.S. Treasury and the proceeds of the Opal Geo tax equity partnership transaction.

Mammoth Complex

Location	Mammoth Lakes, California
Generating Capacity	29 MW
Number of Power Plants	Three (G-1, G-2, and G-3).
Technology	The Mammoth complex utilizes air cooled binary systems.
Subsurface Improvements	Ten production wells and five injection wells are connected to the plants through a gathering system.
Major Equipment	Two new OECs and six turbo-expanders together with the Balance of Plant equipment.
Age	The G-1 plant commenced commercial operation in 1984 and the G-2 and G-3 power plants commenced commercial operation in 1990. We recently replaced the equipment at the G-1 plant with new OECs.
Land and Mineral Rights	The Mammoth complex is comprised mainly of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants.
	The complex’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The average resource temperature is 339 degrees Fahrenheit.
	The Casa Diablo/Basalt Canyon geothermal field at Mammoth lies on the southwest edge of the resurgent dome within the Long Valley Caldera. It is believed that the present heat source for the geothermal system is an active magma body underlying the Mammoth Mountain to the northwest of the field. Geothermal waters heated by the magma flow from a deep source (greater than 3,500 feet) along faults and fracture zones from northwest to southeast east into the field area.
	The produced fluid has minimal scaling potential.

Resource Cooling	In the last three years the temperature has stabilized and there has been no notable decline.
Power Purchaser	G1 and G3 plants — PG&E and G2 plant — Southern California Edison.
PPA Expiration Date	G-1 and G-3 plants — 2034 and G-2 plant — 2027.
Financing	The prior financing transactions covering the Mammoth complex have been fully paid off.

McGinness Hills Complex

Location	Lander County, Nevada
Generating Capacity	90 MW
Number of Power Plants	Two (first phase and second phase)

Technology	The McGinness Hills complex utilizes an air cooled binary system.
Subsurface Improvements	Ten production wells and six injection wells are connected to the power plant.
Material Equipment	Six air cooled OECs with the Balance of Plant equipment.
Age	The first phase power plant commenced commercial operation on July 1, 2012, and the second phase power plant commenced commercial operation on February 1, 2015.
Land and Mineral Rights	The McGinness Hills complex is comprised of private and BLM leases. The leases require annual rental payments, as described above in "Description of Our Leases and Lands". The rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Resource Information	The McGinness Hills geothermal reservoir is contained within a network of fractured rocks over an area at least three square miles. The reservoir is contained in both Tertiary intrusive and Paleozoic sedimentary (basement) rocks. The thermal fluids within the reservoir are inferred to flow upward through the basement rocks along the NNE-striking faults at several fault intersections. The thermal fluids then generally outflow laterally to the NNE and SSW along the NNE-striking faults. No modern thermal manifestations exist at McGinness Hills, although hot spring deposits encompass an area of approximately 0.25 square miles and indicate a history of surface thermal fluid flow. The resource temperature averages 335 degrees Fahrenheit and the fluids are sourced from the reservoir between 2,000 and 5,000 feet below the surface.
Resource Cooling	The temperature has been stable with no notable cooling since the first phase power plant began operation.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2033
Financing	The power plants were financed through the sale of our OFC 2 Senior Secured Notes, an ITC cash grant from the U.S. Treasury for the first phase power plant and the proceeds of the Opal Geo tax equity partnership transaction.

OREG 1 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline in North and South Dakota.
Generating Capacity	22 MW
Number of Units	Four
Technology	The OREG 1 power plant utilizes our air cooled OECs.
Major Equipment	Four WHOH and four OECs together with the Balance of Plant equipment.
Age	The OREG 1 power plant commenced commercial operation in 2006.
Land	Easement from NBPL.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Basin Electric Power Cooperative

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PPA Expiration Date	2031
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD, which has a direct ownership interest in the Puna complex, the Don A. Campbell phase 1 power plant, the OREG 1, OREG 2, and OREG 3 power plants as well as an indirect ownership interest in the Don A. Campbell phase 2 power plant.

OREG 2 Power Plant

Location	Four gas compressor stations along the Northern Border natural gas pipeline; one in Montana, two in North Dakota, and one in Minnesota.
Generating Capacity	22 MW
Number of Units	Four
Technology	The OREG 2 power plant utilizes our air cooled OECs.
Major Equipment	Four WHOH and four OECs together with the Balance of Plant equipment.
Age	The OREG 2 power plant commenced commercial operation during 2009.
Land	Easement from NBPL.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Basin Electric Power Cooperative
PPA Expiration Date	2034
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD, which has a direct ownership interest in the Puna complex, the Don A. Campbell phase 1 power plant, the OREG 1, OREG 2, and OREG 3 power plants as well as an indirect ownership interest in the Don A. Campbell phase 2 power plant.

OREG 3 Power Plant

Location	A gas compressor station along Northern Border natural gas pipeline in Martin County, Minnesota.
Generating Capacity	5.5 MW
Number of Units	One
Technology	The OREG 3 power plant utilizes our air cooled OECs.
Major Equipment	One WHOH and one OEC along with the Balance of Plant equipment.
Age	The OREG 3 power plant commenced commercial operation during 2010.
Land	Easement from NBPL.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Great River Energy
PPA Expiration Date	2029
Financing	Corporate funds.
Supplemental Information	In April 2015, we closed an equity transaction with Northleaf in which Northleaf acquired a 36.75% equity interest in ORPD, which has a direct ownership interest in the Puna complex, the Don A. Campbell phase 1 power plant, the OREG 1, OREG 2, and OREG 3 power plants as well as an indirect ownership interest in the Don A. Campbell phase 2 power plant.

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OREG 4 Power Plant

Location	A gas compressor station along natural gas pipeline in Denver, Colorado.
Generating Capacity	3.5 MW
Number of Units	One
Technology	The OREG 4 power plant utilizes our air cooled OECs.
Major Equipment	Two WHOH and one OEC together with the Balance of Plant equipment.
Age	The OREG 4 power plant commenced commercial operation during 2009.
Land	Easement from Trailblazer Pipeline Company.
Access to Property	Direct access to the plant from public roads.
Power Purchaser	Highline Electric Association
PPA Expiration Date	2029
Financing	Corporate funds.

Ormesa Complex

Location	East Mesa, Imperial County, California
Generating Capacity	40 MW
Number of Power Plants	Three (OG I, OG II and GEM 3). The GEM 2 plant was taken off line during 2015 due to plant operation optimization.
Technology	The OG I and OG II plants utilize a binary system and the GEM 3 plant utilizes a flash system. The complex uses a water cooling system.
Subsurface Improvements	24 production wells and 57 injection wells connected to the plants through a gathering system.
Material Major Equipment	8 OECs and one steam turbine with the Balance of Plant equipment.

Age	The various OG I plants commenced commercial operation between 1987 and 1989, and the OG II plant commenced commercial operation in 1988. Between 2005 and 2007 a significant portion of the old equipment in the OG plants was replaced (including turbines through repowering). The GEM plant commenced commercial operation in 1989, and a new bottoming unit was added in 2007.
Land and Mineral Rights	The Ormesa complex is comprised of BLM leases. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The resource temperature ranges from 280 degrees Fahrenheit to 343 degrees Fahrenheit depending on which production wells are used. Production is from sandstones. Productive sandstones are from 1,800 to 6,000 feet, and have only matrix permeability. The currently developed thermal anomaly was created in geologic time by conductive heating and direct outflow from an underlying convective fracture system. Produced fluid salinity ranges from 2,000 ppm to 13,000 ppm, and minor scaling and corrosion potential is chemically inhibited.

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Resource Cooling	In the last year, the temperature has declined by one degree Fahrenheit.
Sources of Makeup Water	Water is provided by the IID.
Power Purchaser	SCPPA under a single PPA.
PPA Expiration Date	November 30, 2042.
Financing	The prior financing transactions covering the Mammoth complex have been fully paid off.
Supplemental Information	On November 30, 2017 we started to sell the electricity generated by the Ormesa complex power plants under a 25-year PPA with SCPPA. This PPA replaced the 30-year SO#4 contract with Southern California Edison. Under the terms of the new PPA, energy from the power plant is sold to SCPPA at a rate of $77.25 per MWh with no annual escalation. Contract capacity is 35 MW with a maximum generation equivalent to a net capacity of about 43 MW.

Puna Complex

Location	Puna district, Big Island, Hawaii
Generating Capacity	38 MW
Number of Power Plants	Two
Technology	The Puna plants utilize our geothermal combined cycle and binary systems. The plants use an air cooled system.
Subsurface Improvements	Six production wells and five injection wells connected to the plants through a gathering system.
Major Equipment	The first plant consists of ten OECs made up of ten binary turbines, ten steam turbines and two bottoming units along with the Balance of Plant equipment. The second plant consists of two OECs along with Balance of Plant equipment.
Age	The first plant commenced commercial operation in 1993. The second plant was placed in service in 2011 and commenced commercial operation in 2012.
Land and Mineral Rights	The Puna complex is comprised of a private lease. The private lease is between PGV and KLP and it expires in 2046. PGV pays an annual rental payment to KLP, which is adjusted every five years based on the CPI.

The state of Hawaii owns all mineral rights (including geothermal resources) in the state. The state has issued a Geothermal Resources Mining Lease to KLP, and KLP in turn has entered into a sublease agreement with PGV, with the state's consent. Under this arrangement, the state receives royalties of approximately three percent of the gross revenues.

Access to Property

Direct access to the leased property is readily available via county public roads located adjacent to the leased property. The public roads are at the north and south boundaries of the leased property.

Resource Information

The geothermal reservoir at Puna is located in volcanic rock along the axis of the Kilauea Lower East Rift Zone. Permeability and productivity are controlled by rift-parallel subsurface fissures created by volcanic activity. They may also be influenced by lens-shaped bodies of pillow basalt which have been postulated to exist along the axis of the rift at depths below 7,000 feet.

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	The distribution of reservoir temperatures is strongly influenced by the configuration of subsurface fissures and temperatures are among the hottest of any geothermal field in the world, with maximum measured temperatures consistently above 650 degrees Fahrenheit.
Resource Cooling	The resource temperature is stable.
Power Purchaser	Three PPAs with HELCO (see "Supplemental Information" below).
PPA Expiration Date	2027
Financing	The Puna complex was financed through an operating lease, an ITC cash grant from the U.S. Treasury and the proceeds of the Northleaf transaction described above.
Supplemental Information	Energy pricing under the PPA with HELCO is**:**

- For the first on-peak 25 MW, based on HELCO's avoided cost.
- For the next on-peak 5 MW, a flat rate of 11.8 cents per kWh escalating by 1.5% per year.
- For the new on-peak 8 MW, 9 cents per kWh for up to 30,000 MWh/year and 6 cents per kWh above 30,000 MWh/year, escalated by 1.5% per year. We signed an agreement for the period between February 1, 2017 and December 31, 2017 that waives the 30,000 kWh threshold requirements such that the price for energy delivered during on-peak hours will be 6 cents per kWh regardless of the amount of MWh delivered. We recently extended the waiver until the end of 2018.
- For the first off-peak 22 MW, based on HELCO's avoided cost.

The off-peak energy above 22 MW is dispatchable:

1. For the first off-peak 5 MW, a flat rate of 11.8 cents per kWh escalating by 1.5% per year.
2. For the energy above 27 MW and up to 38 MW, 6 cents per kWh escalating by 1.5% per year.

The capacity payment for the first 30 MW $160 kW/year for the first 25 MW and $100.95 kW/year for the additional 5 MW. For the new eight MW power plant the annual capacity payment is $2 million.

Steamboat Complex

Location	Steamboat, Washoe County, Nevada
Generating Capacity	70 MW

Number of Power Plants	Six (Steamboat 2 and 3, Burdette (Galena 1), Steamboat Hills, Galena 2 and Galena 3).
Technology	The Steamboat complex utilizes a binary system (except for Steamboat Hills, which utilizes a single flash system). The complex uses air and water cooling systems.
Subsurface Improvements	25 production wells and 12 injection wells connected to the plants through a gathering system.
Major Equipment	Nine individual air-cooled OECs and one water-cooled OEC, and one steam turbine together with the Balance of Plant Equipment.

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Age	The power plants commenced commercial operation in 1992, 2005, 2007 and 2008. During 2008, the Rotoflow expanders at Steamboat 2 and 3 were replaced with four turbines manufactured by us.
Land and Mineral Rights	The total Steamboat area is comprised of 41% private leases, 41% BLM leases and 18% private land owned by us. The leases are held by production. The scheduled expiration dates for all of these leases are after the end of the expected useful life of the power plants. The complex's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands". We have easements for the transmission lines we use to deliver power to our power purchasers.
Resource Information	The resource temperature at the lower area averages 270 degrees Fahrenheit. The resource at Steamboat Hills averages 325 degrees Fahrenheit. The Steamboat geothermal field is a typical basin and range geothermal reservoir. Large and deep faults that occur in the rocks allow circulation of ground water to depths exceeding 10,000 feet below the surface. Horizontal zones of permeability permit the hot water to flow eastward in an out-flow plume. The Steamboat Hills and Galena 2 power plants produce hot water from fractures associated with normal faults. The rest of the power plants acquire their geothermal water from the horizontal out-flow plume. The water in the Steamboat reservoir has a low total solids concentration. Scaling potential is very low unless the fluid is allowed to flash which will result in calcium carbonate scale. Injection of cooled water for reservoir pressure maintenance prevents flashing.
Resource Cooling	The Steamboat Hills area resource temperature decline rate is 4°F per year and the Lower Steamboat decline rate is 3°F per year.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Sources of Makeup Water	Water is provided by condensate and the local utility.
Power Purchaser	Sierra Pacific Power Company (for Steamboat 2 and 3, Burdette (Galena1), Steamboat Hills, and Galena 3) and Nevada Power Company (for Galena 2).
PPA Expiration Date	Steamboat 2 and 3 — 2022, Burdette (Galena1) — 2026, Steamboat Hills — 2018, Galena 3 — 2028, and Galena 2 — 2027.
Financing	Financings were fully paid.
Supplemental information	In 2017 we ceased operation of a well due to pump failures and connected a cooler well that created a significant reduction in the temperature compared to last year.

Tungsten Mountain* *(U.S.)

Location	Churchill County, Nevada
Generating Capacity	26 MW
Number of Power Plants	One
Technology	The Tungsten Mountain power plant utilizes an air cooled binary system.

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Subsurface Improvements	Four production and three injection wells are connected to the power plant.
Major Equipment	One air cooled OEC with the Balance of Plant equipment.
Age	The power plant commenced commercial operation on December 1, 2017.
Land and Mineral Rights	The Tungsten Mountain area is comprised of BLM land.
Resource Information	The project exploits blind resource (no hot springs or fumaroles) in an area of complex faulting associated with the range front fault on the western side of Edwards Creek Valley. Wells are 1,650 to 4,500 feet deep. Production temperature is approximately 290 degrees Fahrenheit with measured high permeability.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	SCPPA PPA until 2043.
Financing	Corporate funds during construction.

Tuscarora Power Plant

Location	Elko County, Nevada
Generating Capacity	18 MW
Number of Power Plants	One
Technology	The Tuscarora power plant utilizes a water cooled binary system.
Subsurface Improvements	Four production and six injection wells are connected to the power plant. A fifth production well is planned for 2018 and should be in place in early 2018.
Major Equipment	Two water cooled OECs with the Balance of Plant equipment.

Age	The power plant commenced commercial operation on January 11, 2012.
Land and Mineral Rights	The Tuscarora area is comprised of private and BLM leases. The leases are currently held by payment of annual rental payments, as described above in “Description of Our Leases and Lands”. The plant’s rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in “Description of Our Leases and Lands”.
Resource Information	The Tuscarora geothermal reservoir consists of an area of approximately 2.5 square miles. The reservoir is contained in both Tertiary and Paleozoic (basement) rocks. The Paleozoic section consists primarily of sedimentary rocks, overlain by tertiary volcanic rocks. Thermal fluid in the native state of the reservoir flows upward and to the north through apparently southward-dipping, basement formations. At an elevation of roughly 2,500 feet with respect to mean sea level, the upwelling thermal fluid enters the tertiary volcanic rocks and flows directly upward, exiting to the surface at Hot Sulphur Springs. The average resource temperature is 332 degrees Fahrenheit.

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Resource Cooling	We expect gradual decline in the cooling trend from two degrees Fahrenheit per year in the next two to three years, to less than one degree Fahrenheit per year over the long term.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Sources of Makeup Water	Water is provided from five water makeup wells.
Power Purchaser	Nevada Power Company
PPA Expiration Date	2032
Financing	OFC 2 Senior Secured Notes, ITC cash grant from the U.S. Treasury and the OrLeaf transaction.
Supplemental information	Due to the drought years, supply of make-up water for the plant cooling system is declining. With the increase in ambient temperatures, during the summer months we have experienced shortfall at levels that required at certain times reduction in plant generation. At the beginning of 2018 a new well started production. Cooling water supply continues to curtail production in the summer.

Foreign Operating Power Plants

The following descriptions summarize certain industry metrics for our foreign operating power plants:

Amatitlan Power Plant (Guatemala)

Location	Amatitlan, Guatemala
Generating Capacity	20 MW
Number of Power Plants	One
Technology	The Amatitlan power plant utilizes an air cooled binary system and a small back pressure steam turbine (one MW).
Subsurface Improvements	Six production wells and two injection wells connected to the plants through a gathering system.
Major Equipment	Two OECs and one steam turbine together with the Balance of Plant equipment.
Age	The plant commenced commercial operation in 2007.

Land and Mineral Rights	Total resource concession area (under usufruct agreement with INDE) is for a term of 25 years starting in April 2003. Leased and company owned property is approximately 3% of the concession area. Under the agreement with INDE, the power plant company pays royalties of 3.5% of revenues up to 20.5 MW generated and 2% of revenues exceeding 20.5 MW generated. The generated electricity is sold at the plant fence. The transmission line is owned by INDE.
Resource Information	The resource temperature is an average of 518 degrees Fahrenheit. The Amatitlan geothermal area is located on the north side of the Pacaya Volcano at approximately 5,900 feet above sea level. Hot fluid circulates up from a heat source beneath the volcano, through deep faults to shallower depths, and then cools as it flows horizontally to the north and northwest to hot springs on the southern shore of Lake Amatitlan and the Michatoya River Valley.

Resource Cooling	Approximately two degrees Fahrenheit per year.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the lease agreement.
Power Purchasers	INDE and another local purchaser.
PPA Expiration Date	The PPA with INDE expires in 2028.
Financing	Senior secured limited recourse project finance loan from Banco Industrial S.A. and Westrust Bank (International) Limited.

Bouillante power plant (Guadeloupe)

Location	Guadeloupe, a French territory in the Caribbean
Generating Capacity	15 MW
Number of Power Plants	One
Technology	The Bouillante power plant uses direct steam turbines.
Subsurface Improvements	Two production wells and one injection well connected to the plant through a gathering system.
Major Equipment	Two steam turbines together with the Balance of Plant equipment.
Age	The first turbine commenced commercial operation in 1995 and the second turbine commenced operation in 2004.
Land and Mineral Rights	Geothermal concession of roughly 24 square miles valid through April 30, 2050. Facilities located on land held in fee, as well as long-term leases and easements.
Resource Information	The resource temperature is an average of 485 degrees Fahrenheit. Production comes from a fault that extends from the mountain into the ocean.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to site through public roads.
Power Purchaser	EDF pursuant to a PPA.
PPA Expiration Date	December 31, 2030.
Financing	Corporate funds

Supplemental information	80% of the project is owned jointly by Ormat and CDC allocated 75% to Ormat and 25% to CDC. Ormat and CDC will gradually increase their combined interest in the project to 85% and Sageos will hold the remaining balance. We plan to convert two idle wells to injection wells to improve reservoir pressure support.
Olkaria III Complex (Kenya)	
Location	Naivasha, Kenya
Generating Capacity	139 MW
Number of Power Plants	Four (Plant 1, Plant 2, Plant 3 and Plant 4).
Technology	The Olkaria III complex utilizes an air cooled binary system.

Subsurface Improvements	18 production wells and five injection wells connected to the plants through a gathering system.
Major Equipment	13 OECs together with the Balance of Plant equipment.
Age	Plant 4 commenced commercial operation in January 2016, Plant 3 in January 2014 and Plant 2 in April 2013. The first phase of Plant 1 commenced operation in 2000 and the second phase in 2009.
Land and Mineral Rights	The total Olkaria III area is comprised of government leases. A license granted by the Kenyan government provides exclusive rights of use and possession of the relevant geothermal resources for an initial period of 30 years, expiring in 2029, which initial period may be extended for two additional five-year terms. The Kenyan Minister of Energy has the right to terminate or revoke the license in the event work in or under the license area stops during a period of six months, or there is a failure to comply with the terms of the license or the provisions of the law relating to geothermal resources. Royalties are paid to the Kenyan government monthly based on the amount of power supplied to the power purchaser and an annual rent. The power generated is purchased at the metering point located immediately after the power transformers in the 220 kV sub-station within the power plant, before the transmission lines, which belong to the utility.
Resource Information	The average resource temperature is 570 degrees Fahrenheit. The Olkaria III geothermal field is on the west side of the greater Olkaria geothermal area located at approximately 6,890 feet above sea level within the Rift Valley. Hot geothermal fluids rise up from deep in the northeastern portion of the concession area, penetrating a low permeability zone below 3,280 feet above sea level to a high productivity, two-phase zone identified between 3,280 and 4,270 feet above sea level.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the lease agreement.
Power Purchaser	KPLC
PPA Expiration Date	Plant 2 - 2033, Plant 1 - 2034, Plant 3 - 2034 and Plant 4 - 2036
Financing	Senior secured project finance loan from OPIC and a subordinated loan from DEG.
Supplemental information	We are planning to add additional 10 MW that will come online during 2018.

Platanares (Honduras)

Location	Copan, Honduras
Generating Capacity	35 MW
Number of Power plants	One
Technology	The Platanares power plant utilizes an air cooled binary system.

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Subsurface Improvements	Four production wells and two injection wells connected to the plant through a gathering system.
Major Equipment	Two OECs together with the Balance of Plant equipment.
Age	The plant commenced commercial operation in September 2017.
Land and Mineral Rights	The Platanares site is located within a geothermal concession granted by the Department of Energy, Natural Resources, Environment, and Mines (SERNA) on fee land owned by GeoPlatanares and on land leased from various private and public entities. The concession conveys to GeoPlatanares the right to exploit the geothermal resources contained within. The transmission corridor consists of easement agreements between GeoPlatanares and various private and public entities.
Resource Information	The Platanares site is located along a narrow river valley in western Honduras. The field is covered mostly by Miocene volcanic deposits. Numerous boiling hot springs and fumaroles emit along active faults along an area around two miles in length. The geothermal reservoir is supported by highly fractured volcanic and metasedimentary rock units. Wells are less than 800 meters deep. Production temperature is 352 degrees Fahrenheit with high productivity.
Resource Cooling	The resource temperature is stable.
Access to Property	Public roads provide access to the Platanares site. In order to improve access for heavy equipment and large loads, GeoPlatanares has entered into a lease agreement with a private landowner for a small segment of road linking two leased parcels
Power Purchaser	ENEE pursuant to a PPA.
PPA Expiration Date	2047
Financing	Corporate funds.
Supplemental Information	We hold the assets, including the project's wells, land, permits and a PPA, under a BOT structure for 15 years from the date the Platanares plant commenced commercial operation on September 26, 2017. A portion of the land on which the project is located is held by us through a lease from a local municipality. The lease is subject to approval by the Honduran Congress because the term of the lease exceeds the term in office of the relevant municipal government. Our project subsidiary has commenced the necessary steps to obtain such approval. We are negotiating project finance debt that will be provided by the OPIC. The financing is expected to be signed and closed following the fulfillment of certain conditions precedent set forth in the loan documents.

Sarulla – SIL and NIL 1(Indonesia)

Location	Tapanuli Utara North Sumatra Namura I Langit area, Indonesia.

Ownership	SOL is a consortium consisting of Medco Energi Internasional Tbk, Inpex Corporation, Itochu Corporation, Kyushu Electric Power Co. Inc., and one of our indirect wholly owned subsidiaries that holds a 12.75% interest.
Generating Capacity	Currently two phases (SIL and NIL 1) are operating with a total capacity of approximately 220 MW (Ormat's ownership share is approximately 28 MW). Ormat's own equipment is producing approximately 40% of the power.

Number of Power plants	Two (SIL and NIL 1)
Technology	Integrated Geothermal Combined Cycle Unit comprised of one back pressure steam turbines and six OECs for each phase (together two steam turbines and 12 OECs.
Subsurface Improvements	About 16 production wells and the same number of injection wells are connected to the plant through a gathering system.
Major Equipment	Two pressure steam turbines and 12 OECs together with its ancillary systems as well as field separation systems; sub-station, internal HV transmission line and other Balance of Plant equipment.
Age	SIL and NIL 1 power plants commenced commercial operation in March and October 2017, respectively.
Land and Mineral Rights	Most of the above ground land for the project was acquired from private owners with some land leased from governmental agencies. Mineral rights are state owned with special agreement for its usage by the project.
Resource Information	Two field areas, NIL and SIL host a steam-liquid-dominated system. Previously drilled wells have temperatures from 275°C to 310°C. Currently most wells are flowing at an average rate of about 750T/Hr per well which is sufficient for over 20 MW electrical production.
Resource Cooling	Since the project commenced operation the resource temperature has been stable.
Access to Property	Access to property for the project has been secured.
Power Purchaser	30-year Energy Sales Contract with PLN (the state electric utility)
PPA Expiration Date	2047
Financing	In May 2014, SOL reached financial closing on $1.17 billion to finance the development of the Sarulla project with a consortium of lenders comprised of JBIC, the Asian Development Bank and six other commercial banks. The project company obtained construction and term loans under a limited recourse financing package backed by political risk guarantee from JBIC.
Supplemental Information	The Sarulla project is owned and operated by the consortium members under the framework of a JOC and ESC. Under the JOC, PT Pertamina Geothermal Energy, the concession holder for the project, has provided the consortium with the right to use the geothermal field, and under the ESC, PLN, the state electric utility, will be the off-taker at Sarulla for a period of 30 years. In addition to our equity holdings in the consortium (12.75%), we provided (under a separate supply contract) the initial conceptual design, the control system and the OECs for the Sarulla power plant.

We are progressing with construction of the third phase, NIL 2, as discussed below.

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Zunil Power Plant (Guatemala)

Location	Zunil, Guatemala
Generating Capacity	23 MW (see "Supplemental Information" below for information on current generating capacity)
Number of Power Plants	One
Technology	The Zunil power plant utilizes an air cooled binary system.
Subsurface	Six production wells and two injection wells are connected to the plant through a gathering system.
Major Equipment	Seven OECs together with the Balance of Plant equipment.
Age	The Zunil power plant commenced commercial operation in 1999.
Land and Mineral Rights	The land owned by the Zunil power plant includes the power plant, workshop and open yards for equipment and pipes storage. Pipelines for the gathering system transit through a local agricultural area's right of way acquired by us. The geothermal wells and resource are owned by INDE. The power generated by the Zunil power plant is sold at our property line; power transmission lines are owned and operated by INDE.
Resource Information	The Zunil geothermal reservoir is hosted in Tertiary volcanic rocks which include overly fractured granodiorite. Production wells produce a reservoir from 536-572 degrees Fahrenheit to a depth of approximately 2,860 to 4,300 feet. A shallow steam cap exists in the production area of the field, and most of the wells produce high enthalpy fluid due to the presence of two-phase conditions in their feed zones. The wells target northwest- and northeast-trending fractures for permeability. These fractures are also thought to control upwelling from the volcanically-heated source. The upwelling fluids form a steam cap, and fluids and steam reach the surface along fractures, forming springs and fumaroles throughout the geothermal field.
Resource Cooling	The resource temperature is stable.
Access to Property	Direct access to public roads.
	INDE

Power Purchaser	
PPA Expiration Date	2034
Supplemental Information	In January 2014, we signed an amendment to the PPA with INDE to extend its term by 15 years until 2034. The PPA amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to Ormat for the term of the amended PPA in exchange for an increase in tariff. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant and to hold a three percent equity interest. The power plant generates approximately 16 MW due to lack of sufficient geothermal resources. We successfully improved the heat supply and gradually increased the generation capacity. We expect that this improvement and the increased tariff will increase the energy portion of revenues.

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According to the PPA amendment, payments for the Zunil plant will be made as follows:

1. Capacity payment:
   a. Until 2019, the capacity payment will be calculated based on a 24 MW generating capacity regardless of the actual performance of the power plant.
   b. From 2019 and thereafter, the capacity payment will be based on actual delivered capacity and the capacity rate will be reduced.
2. Energy payment:
   a. From 2014 until 2034, the energy payment will include a geothermal field operation and maintenance rate based on actual delivered energy in addition to the energy rate on actual delivered energy.
   b. From 2019 and thereafter, the energy rate on delivered energy will increase and will compensate the reduction in the capacity rate.

Projects under Construction

We have several projects in various stages of construction, including three projects that we have fully released for construction and three projects that are in initial stages of construction.

The following is a description of projects in the U.S., Kenya and Indonesia that were released for, and are in different stages of, construction. These projects are expected to have a total generating capacity of 72 MW (representing our interest). In addition, we are planning to add 4 MW to the Brady complex, as described above.

McGinness Hills Phase 3 (U.S.)

Location	Lander County, Nevada
Projected Generating Capacity	48 MW
Projected Technology	The power plant will utilize an air cooled binary system.
Condition	Engineering and procurement is ongoing, and drilling is in process.
Subsurface Improvement	We plan to drill five new production wells and three injection wells.

Land and Mineral Rights	The McGinness Hills site is comprised of private and BLM leases. The leases require annual rental payments, as described above in "Description of Our Leases and Lands". The rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Resource Information	The McGinness Hills geothermal reservoir is contained within a network of fractured rocks over an area of at least three square miles. The reservoir is contained in both Tertiary intrusive and Paleozoic sedimentary (basement) rocks. The thermal fluids within the reservoir are inferred to flow upward through the basement rocks along the NNE-striking faults at several fault intersections. The thermal fluids then generally outflow laterally to the NNE and SSW along the NNE-striking faults. No modern thermal manifestations exist at McGinness Hills, although hot spring deposits encompass an area of approximately 0.25 square miles and indicate a history of surface thermal fluid flow. The resource temperature averages 335 degrees Fahrenheit and the fluids are sourced from the reservoir at elevations between 2,000 to 5,000 feet below the surface.

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Power Purchaser	SCPPA.
Financing	Corporate finance.
Projected Operation	By the end of 2018.
Supplemental Information	Western Watersheds Project (WWP) filed a notice of appeal and petition for standing with respect to a BLM decision approving Addendum 2 to Operation Plan & Utilization Plan for the MGH project. The appeal alleges that the BLM decision authorizing construction and operation of MGH Phase 3 causes harm to WWP and its members by allowing degradation of the wildlife habitat of the Greater sage-grouse in that area.

Olkaria III – Plant 1 Repowering (Kenya)

Location	Naivasha, Kenya
Projected Generating Capacity	10 MW
Projected Technology	The power plant will utilize an air cooled binary system.
Condition	Engineering and manufacturing are completed. Plant construction is ongoing. The power plant is planned to be on line early in 2018
Subsurface Improvement	Two wells were drilled successfully in 2017.
Land and Mineral Rights	The Olkaria III site is comprised of government leases. See description above under “Olkaria III Complex”.
Resource Information	The Olkaria III geothermal field is located on the west side of the greater Olkaria geothermal area within the Rift Valley at approximately 6,890 feet above sea level. Hot geothermal fluids rise up from deep in the northeastern portion of the concession area through low permeability at a shallow depth to a high productivity two-phase region from 3,280 to 4,270 feet above sea level.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the lease agreement.
Power Purchaser	KPLC.
Financing	Corporate finance.

Projected Operation	In the second half of 2018.
Supplemental Information	We plan to add an additional OEC to the existing Olkaria III Plant 1. The electricity generated from the new unit will be sold under the Olkaria III Plant 1 PPA.

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Sarulla NIL 2 (Indonesia)

Location	Tapanuli Utara North Sumatra Namura I Langit area, Indonesia.
Ownership	SOL is a consortium consisting of Medco Energi Internasional Tbk, Inpex Corporation, Itochu Corporation, Kyushu Electric Power Co. Inc., and one of our indirect wholly owned subsidiaries that holds a 12.75% interest.
Projected Generating Capacity	One phase, NIL 2, has a total projected generating capacity of approximately 110 MW (Ormat's share is approximately 14 MW).
Projected Technology	Integrated Geothermal Combined Cycle Unit comprised of one back pressure steam turbine and six OECs.
Condition	The first two phases (SIL and NIL 1, with a combined generating capacity of 220 MW) commenced commercial operation in March and October 2017, respectively. For the third phase, NIL 2, engineering, procurement and construction work at the site are in progress and all of Ormat's equipment has been delivered and installed. Drilling for the third phase is still ongoing and the project has achieved to date, based on preliminary estimates, 100% of the required production and injection capacity.
Land and Mineral Rights	Most of the aboveground land for the project was acquired from private owners with some land leased from governmental agencies. Mineral rights are state owned with special agreement for its usage by the project.
Resource Information	Two field areas, NIL and SIL host a steam-liquid-dominated system. Previously drilled wells have temperatures from 275°C to 310°C. Currently most wells are flowing at an average rate of about 750T/Hr per well which is sufficient for over 20 MW electrical production.
Access to Property	Access to property for the project has been secured.
Power Purchaser	30-year Energy Sales Contract with PLN (the state electric utility)
Financing	In May 2014, SOL reached financial closing on $1.17 billion to finance the development of the project with a consortium of lenders comprised of JBIC, the Asian Development Bank and six other commercial banks. Under this financing, the project company obtained construction and term loans under a limited recourse financing package backed by political risk guarantee from JBIC.
Projected Operation	NIL 2 will be commissioned in two stages. Approximately 80 MW will be commissioned in the first quarter of 2018 and approximately 30 MW will be commissioned by mid-April 2018.
Supplemental Information	The Sarulla project is owned and operated by the consortium members under the framework of a JOC and ESC. Under the JOC, PT Pertamina Geothermal Energy, the concession holder for the project, has provided the consortium with the right to use the geothermal field, and under the ESC, PLN, the

state electric utility, is the off-taker at Sarulla for a period of 30 years.

In addition to our equity holdings in the consortium, we designed the Sarulla power plant and supplied our OECs to the power plant.

The project has missed a few milestones defined under the loan documents but has received waivers from the lenders and the project is currently in compliance with the lenders' requirements. The project experienced delays in field development and cost overruns resulting from delays and excess drilling costs. Due to the cost overrun in drilling, the lenders have requested from the sponsors to commit to contributing additional equity. The sponsors have agreed, and financing documents were revised to reflect this request. With respect to our role as a supplier, all contractual milestones under the supply agreement were achieved.

The following is a description of projects in California and Nevada with an expected total generating capacity of 42 MW that are in an initial stage of construction:

Carson Lake Project (U.S.)

Location	Churchill County, Nevada
Projected Generating Capacity	10 MW
Projected Technology	The Carson Lake power plant will utilize a binary system.
Condition	Initial stage of construction.
Subsurface Improvements	We drilled one well in 2016 that did not meet our commercial criteria and another in 2017 that tested favorably. Planning is in process for next steps including a flow test to evaluate reservoir volume.
Land and Mineral Rights	The Carson Lake project site is comprised of BLM leases. The leases are currently held by the payment of annual rental payments, as described above in "Description of Our Leases and Lands." Ormat holds the leases under the initial extension of the primary term which expires in 2021. An additional extension of the primary term may be filed in 2021 for an additional 5 years. If commercial production occurs during either of these periods, the leases will be extended for 35 years with the possibility of additional extension for 55 years. The project's rights to use the geothermal and surface rights under the leases are subject to various conditions, as described above in "Description of Our Leases and Lands".
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.

Resource Information	The expected average temperature of the resource cannot be estimated as field development has not been completed yet.
Power Purchaser	SCPPA.
PPA Expiration Date	2043
Financing	Corporate funds.

Projected Operation	We are currently continuing with drilling activity and based on these results, we will evaluate the next development steps for the project and its COD.
Supplemental Information	We signed a Small Generator Interconnection Agreement with NV Energy in December 2017.

CD4 Project (Mammoth Complex) (U.S.)

Location	Mammoth Lakes, California
Projected Generating Capacity	25 MW
Projected Technology	The CD4 power plant will utilize an air cooled binary system.
Condition	Initial stage of construction.
Subsurface Improvements	We have completed two production wells, one of which was previously considered an injection well. In 2017 we drilled a core well to begin baseline monitoring, as required by our permit. Continued drilling is planned for 2018.
Land and Mineral Rights	The Mammoth complex is comprised mainly of BLM leases, which are held by production and are subject to a unitization agreement.
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted pursuant to the leases.
Resource Information	The expected average temperature of the resource is 350-370 degrees Fahrenheit.
Power Purchaser	We have not executed a PPA.
Financing	Corporate funds.
Projected Operation	2020, subject to PPA execution.
Supplemental Information	We signed a Wholesale Distribution Access Tariff Cluster Large Generator Interconnection Agreement with SCE in December 2017.

Tungsten Mountain Solar (U.S.)

Location	Churchill County, Nevada
Projected Generating Capacity	7 MW AC (8.5 MW DC)
Projected Technology	Solar PV

Condition	Development (engineering and permitting)
Land	The Tungsten Mountain Solar site is comprised of BLM leases
Access to Property	Direct access to public roads from the leased property and access across the leased property are provided under surface rights granted in leases from BLM.
Power Purchaser	SCPPA
PPA Expiration Date	2043
Financing	Corporate funds
Projected Operation	By the end of 2018

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Supplemental Information	We plan to install Solar PV systems in the Tungsten Mountain geothermal power plant to reduce internal (i.e. parasitic) load. We are in the process of amending the Tungsten Mountain geothermal Large Generator Interconnection Agreement with NV Energy to reflect this addition of solar PV systems.

Future Projects

Projects under Various Stages of Development

We also have projects under various stages of development in the U.S., Guadeloupe and Kenya. We expect to continue to explore these and other opportunities for expansion so long as they continue to meet our business objectives and investment criteria.

The following is a description of the projects currently under various stages of development and for which we are able to estimate their expected generating capacity. Upon completion of these projects, the generating capacity of our geothermal projects would increase by approximately 73 MW to 78 MW (representing our interest). However, we prioritize our investments based on their readiness for continued construction and expected economics and therefore we are not planning to invest in all of such projects in 2018.

Bouillante power plant (Guadeloupe)

We are planning to increase the capacity of the Bouillante project by an additional 10 MW. The power plant currently sells its electricity under a 15-year PPA with EDF that was entered into in February 2016 and allows us to sell up to 14.75 MW. We expect this expansion to be completed in 2020, subject to PPA execution.

Menengai Project (Kenya)

On November 3, 2014, our majority owned Kenyan subsidiary (Project Company) signed a 25-year PPA with KPLC and a project implementation and steam supply agreement (PISSA) with GDC for the 35 MW Menengai geothermal project in Kenya. The Project Company is owned by Ormat (51%), Symbion Power LLC (24.5%) and Civicon Ltd.

(24.5%).

Under the PISSA, the Project Company will finance, design, construct, install, operate and maintain the 35 MW Menengai steam power plant on a build-own-operate (BOO) basis for 25 years. GDC, which is wholly owned by the Kenyan government, will develop the geothermal resource, supply the steam for conversion to electricity and maintain the geothermal field through the term of the agreement. The Project Company expects to start construction upon financial closing.

Puna Enhancement Project (Hawaii)

We are planning to replace 10 old steam units with two new OECs and to upgrade the existing auxiliary equipment. This upgrade will increase the Puna complex generating capacity by 8 MW to 46 MW. We have entered into negotiations with HELCO to secure a PPA for increased generation during the original term of the existing PPAs and to extend the period beyond 2027. We expect the upgrade to be completed by late 2019 or early 2020.

Dixie Meadows

We are currently developing the 15 MW to 20 MW Dixie Meadows geothermal power plant in Churchill County, Nevada. Following evaluation of drilling results, we have concluded that injection wells should be located in an area which is currently designated as protected land. We are exploring ways to remove the federal designation. Until we complete this process, we have put this project on hold.

Steamboat Solar

We are planning to develop a 5 MW Solar PV project on the site of the Steamboat geothermal complex. We plan to install Solar PV systems to reduce internal consumption loads.

Future Prospects

We have a substantial land position that is expected to support future development and on which we have started or plan to start exploration activity. When deciding whether to continue holding lease rights and/or to pursue exploration activity, we diligently prioritize our prospective investments, taking into account resource and probability assessments in order to make informed decisions about whether a particular project will support commercial operation.

As a result, during fiscal year 2017, we discontinued exploration activities at four prospects, the Ungaran prospect in Indonesia, Glass Buttes - Midnight Point in Oregon, and Tuscarora - Phase 2 and Don A. Campbell - phase 3 in Nevada. We added two new prospects in 2017, the Tungsten Mountain – Phase 2 and Twin Buttes in Nevada.

Our current land position is comprised of various leases, concessions and private land for geothermal resources of approximately 264,000 acres in 32 prospects including the following:

Nevada (15)

1. Alum	Exploration studies in progress;
2. Baltazor	Under exploration drilling;
3. Colado	Under exploration drilling;
4. Dixie Comstock	Exploration studies in progress;
5. Edwards Creek	Under exploration drilling;
6. Horsehaven (formerly Beowawe)	Exploration studies in progress;
7. North Valley	Exploration studies in progress;
8. New York Canyon	Exploration studies in progress;
9. Pearl Hot Springs	Lease acquired but no further action has been taken yet;
10. Ruby Valley	Lease acquired but no further action has been taken yet;
11. Rhodes Marsh	Exploration studies in progress;
12. South Brady	Exploration studies in progress;
13. Trinity	Exploration studies in progress;

14. Tungsten Mountain – Phase 2 Assessment for future expansion; and
15. Twin Buttes Lease acquired but no further action has been taken yet.

California (3)

1. Glamis Exploration studies in progress;
2. Rhyolite Plateau Exploration studies in progress; and
3. Truckhaven Exploration studies in progress.

Oregon (2)

1. Crump Geyser Under exploration drilling; and
2. Lakeview/ Goose Lake Exploration studies in progress

New Mexico (1)

1. Rincon Exploration studies in progress.

Utah (2)

1. Pavant Exploration studies in progress;
2. Roosevelt Hot Springs Exploration studies in progress.

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Guatemala (2)

1. Amatitlan Phase II Exploration studies in progress; and
2. Tecumburu Waiting for additional land acquisition.

Guadeloupe (1)

1. Bouillante Exploration studies in progress.

New Zealand (1)

1. Tikitere Signed BOT agreement; exploratory drilling is pending resource consent acceptance.

Honduras (1)

1. San Ignacio (12 Tribes) Exploration studies in progress.

Ethiopia (4)

1. Boku Under exploration studies;
2. Dofan Under exploration studies;
3. Dugumo Fango Under exploration studies; and
4. Shashamane Under exploration studies;

Storage Projects

In addition to our Geothermal activity, we are currently working to develop energy storage projects in the U.S. including the following:

ACUA

We are developing a 1 MW/1 MWh behind the meter energy storage system that will be installed in the Atlantic County Utility Authority's (ACUA) wastewater treatment plant in Atlantic City, New Jersey. We will own and operate the battery energy storage systems to create energy savings for ACUA, including by participating in PJM's frequency regulation market. Commercial operation is expected in March 2018.

Stryker and Plumstead

We are developing two 20 MW/20 MWh IFM energy storage systems. The Stryker project is located near Allentown, NJ and the Plumsted project is located near Trenton, NJ. We are acting as EPC lead and owner and operator of both projects. The energy storage systems will participate in PJM's frequency regulation market.

Operations of our Product Segment

Power Units for Geothermal Power Plants. We design, manufacture, and sell power units for geothermal electricity generation, which we refer to as OECs. Our customers include contractors and geothermal plant owners and operators.

The power units are usually paid for in installments, in accordance with milestones set forth in the supply agreement. Sometimes we agree to provide the purchaser with spare parts (or alternatively, with a non-exclusive license to manufacture such parts). We provide the purchaser with at least a 12-month warranty for such products. We usually also provide the purchaser (often upon receipt of advances made by the purchaser) with a guarantee, which partially terminates upon delivery of the equipment to the site and terminates in full at the end of the warranty period. The guarantees are typically supported by letters of credit.

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Power Units for Recovered Energy-Based Power Generation. We design, manufacture, and sell power units used to generate electricity from recovered energy or so-called “waste heat”. Our existing and target customers include interstate natural gas pipeline owners and operators, gas processing plant owners and operators, cement plant owners and operators, and other companies engaged in other energy-intensive industrial processes. We have two different business models for this product line.

The first business model, which is similar to the model utilized in our geothermal power generation business, consists of the development, construction, ownership, and operation of recovered energy-based generation power plants. Pursuant to this business model, we enter into agreements to purchase industrial waste heat, and long-term PPAs with off-takers to sell the electricity generated by the REG unit that utilizes such industrial waste heat. The power purchasers in such cases generally are investor-owned electric utilities or local electrical cooperatives. This is the business model for our OREG 1, 2, 3 and 4 power plants.

Pursuant to the second business model, we construct and sell the power units for recovered energy-based power generation to third parties for use in “inside-the-fence” installations or otherwise. Our customers include gas processing plant owners and operators, cement plant owners and operators and companies in the process industry.

Remote Power Units and other Generators. We design, manufacture and sell fossil fuel powered turbo-generators with capacities ranging from 200 watts to 5,000 watts, which operate unattended in extreme hot or cold climate conditions. The remote power units supply energy to remote unmanned installations and along communications lines, and provide cathodic protection along gas and oil pipelines. Our customers include contractors installing gas pipelines in remote areas. In addition, we manufacture and sell generators, including heavy duty direct current generators, for various other uses. The terms for sale of the turbo-generators are similar to those for the power units we produce for power plants.

EPC of Power Plants. We engineer, procure and construct, as an EPC contractor, geothermal and recovered energy power plants on a turnkey basis, using power units we design and manufacture. Our customers are geothermal power plant owners as well as our target customers for the sale of our recovered-energy based power units described above. Unlike many other companies that provide EPC services, we believe we have an advantage in that we are using our own manufactured equipment and thus have better quality and control over the timing and delivery of equipment and related costs. The consideration for such services is usually paid in installments, in accordance with milestones set forth in the EPC contract and related documents. We usually provide performance guarantees or letters of credit securing our obligations under the contract. Upon delivery of the plant to its owner, such guarantees are replaced with a warranty guarantee, usually for a period ranging from 12 to 36 months. The EPC contract usually places a cap on our liabilities for failure to meet our obligations thereunder.

In connection with the sale of our power units for geothermal power plants, power units for recovered energy-based power generation, remote power units and other generators, we enter into sales agreements, from time to time, with sales representatives for the marketing and sale of such products pursuant to which we are obligated to pay commissions to such representatives upon the sale of our products in the relevant territory covered by such agreements by such representatives or, in some cases, by other representatives in such territory.

Our manufacturing operations and products are certified ISO 9001, ISO 14001, American Society of Mechanical Engineers, and TÜV, and we are an approved supplier to many electric utilities around the world.

Backlog

We have a product backlog of approximately $243.0 million as of February 26, 2018, which includes revenues for the period between January 1, 2018 and February 26, 2018, compared to $251.0 million as of February 27, 2017, which included revenues for the period between January 1, 2017 and February 27, 2017.

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The following is a breakdown of the Product segment backlog as of March 1, 2018 ($ in millions):

	Expected Completion of the Contract	**Sales Expected to be Recognized in 2018**	**Sales Expected to be Recognized in the years following 2018**	**Expected Until End of Contract**
Geothermal	2019	177.5	57	234.5
Recovered Energy	2018	0.9	0.0	0.9
Other	2018	7.6	0.0	7.6
Total		**186.0**	57.0	**243.0**

Competition

In our Electricity segment, we face competition from geothermal power plant owners and developers as well as other renewable energy providers.

In our Product segment, we face competition from power plant equipment manufacturers and system integrators as well as engineering or projects management companies.

As we implement our new strategic plan, we will face competition from a number of sources, many of which may have resources, industry experience, market acceptance or other advantages we do not have. For example, expanding into new technologies, such as energy storage, or new markets, such as C&I, will involve competition from companies that already have established businesses in those technologies and markets as well as companies seeking to acquire established businesses and other new market entrants like us.

Electricity Segment

Competition in the Electricity segment is particularly marked in the very early stage of either obtaining the rights to the resource for development of future projects or acquiring a site already in a more advanced stage of development. Once we or other developers obtain such rights or own a power plant, competition is limited. From time to time and in different jurisdictions competing geothermal developers become our customers in the Product segment.

Our main competitors in the geothermal sector in the U.S. are CalEnergy, Calpine Corporation, Terra-Gen Power LLC, Enel Green Power S.p.A and other smaller pure play developers. Outside the U.S., in many cases our competitors are companies that are gaining experience developing geothermal projects in their own countries such as Mercury (formerly Mighty River Power) and Contact Energy in New Zealand, and local developers and steam turbine manufacturers in Indonesia. Some of our competitors are now seeking to take the local experience they have gained and develop geothermal projects in other countries. These competitors include Energy Development Corporation from the Philippines and Enel Green Power from Italy. Some Turkish developers are also focusing on the international market. Additionally, we face competition from small country-specific companies.

In obtaining new PPAs, we also face competition from companies engaged in the power generation business from other renewable energy sources, such as wind power, biomass, solar power and hydro-electric power. In the last few years, competition from the wind and solar power generation industries has increased significantly.

As a geothermal company, we are focused on niche markets where our baseload and flexibility advantages can allow us to develop competitive projects.

In the demand response markets, our Viridity business competes primarily with specialized demand management providers rather than with the traditional curtailment service providers. Viridity differentiates itself from its competitors by its proprietary software and analytical strengths, wider use cases, customer base, business model, and market presence.

The energy storage and energy management space is comprised of many companies divided into different verticals and sub verticals like OEMs, integrators, battery management systems, energy management systems, battery producers, power conversion systems, DER system design and optimization, micro grids design, monitoring and control and companies that are realizing storage assets' economic value through the optimization of storage assets' operation in real time electricity markets. Our proprietary software, analytical operational platform and significant differentiated experience in storage operation and integration with electricity markets, allow us to provide multiple value streams (value stacking) from a single storage installation. We have continued and plan to continue to grow our Viridity business in these markets.

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Product Segment

Our competitors among power plant equipment suppliers are divided into high enthalpy and low enthalpy competitors. Our main high enthalpy competitors are industrial steam turbine manufacturers such as Mitsubishi Hitachi Power Systems, Fuji Electric Co., Ltd. and Toshiba Corporation of Japan, GE/Nuovo Pignone brand and Ansaldo Energia of Italy. As noted above, in 2015, we signed a strategic collaboration agreement with one of these competitors, Toshiba Corporation.

Our low enthalpy competitors are binary systems manufacturers using the Organic Rankine Cycle such as Fuji Electric Co., Ltd of Japan, Exergy of Italy, Mitsubishi Hitachi Power Systems (which acquired Turboden) and recently Egesim, a Turkish electrical contractor who is collaborating with Atlas Copco in the Turkish market. While we believe that we have a distinct competitive advantage based on our accumulated experience and current worldwide share of installed binary generation capacity (which is approximately 85%), an increase in competition, which we are currently experiencing, has started to impact our ability to secure new purchase orders from potential customers. The increased competition led to a reduction in the prices that we are able to charge for our binary equipment, which in turn impacted our profitability.

In the REG business, our competitors are other Organic Rankine Cycle manufacturers (such as GE and Mitsubishi/Turboden), manufacturers that use Kalina technology (such as Geothermal Energy Research & Development Co., Ltd in Japan), other manufacturers of conventional steam turbines and small developers of small scale ORCs.

Currently, none of our competitors compete with us in both the Electricity and the Product segments.

In the case of proposed EPC projects, we also compete with other service suppliers, such as project/engineering companies.

Customers

All of our revenues from the sale of electricity in the year ended December 31, 2017 were derived from fully-contracted energy and/or capacity payments under long-term PPAs with governmental and private utility entities. Southern California Edison, Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), HELCO, SCPPA and KPLC accounted for 4.3%, 18.1%, 5.5%, 10.1% and 15.9% of total revenues, respectively, for the year ended December 31, 2017.

Based on publicly available information, as of December 31, 2017, the issuer ratings of Southern California Edison, HELCO, Sierra Pacific Power Company, Nevada Power Company, SCPPA, Pacific Gas & Electric and EDF were as set forth below:

Issuer	**Standard & Poor's Ratings Services**	**Moody's Investors Service Inc**.
Southern California Edison	BBB+ (Stable)	A2 (Stable)
HELCO	BBB- (Stable)	Rating withdrawn
Sierra Pacific Power Company	A (Stable)	Baa1 (Stable)
Nevada Power Company	A (Stable)	Baa1 (Stable)
SCPPA	BBB+ (Stable)	Aa2 (Stable)
Pacific, Gas and Electric	A- (Watch Negative)	A2 (Rating under review)
EDF	A- (Negative)	A3 (Stable)

The credit ratings of any power purchaser may change from time to time. There is no publicly available information with respect to the credit rating or stability of the power purchasers under the PPAs for our foreign power plants.

Our revenues from the Product segment are derived from contractors or owners or operators of power plants, process companies, and pipelines.

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Raw Materials, Suppliers and Subcontractors

In connection with our manufacturing activities, we use raw materials such as steel and aluminum. We do not rely on any one supplier for the raw materials used in our manufacturing activities, as all of these raw materials are readily available from various suppliers.

We use subcontractors for some of the manufacturing activities with respect to our products components and for construction activities with respect to our power plants, which allows us to expand our construction and development capacity on an as-needed basis. We are not dependent on any one subcontractor and expect to be able to replace any subcontractor or assume such manufacturing and construction activities ourselves, if necessary or desirable, without adverse effect to our operations.

Employees

As of December 31, 2017, we employed 1,303 employees, of which 527 were located in the U.S., 579 were located in Israel and 197 were located in other countries. We expect that future growth in the number of our employees will be mainly attributable to the purchase and/or development of new power plants.

As of December 31, 2017, the only employees that are represented by a labor union are the employees of our recently acquired Bouillante power plant located in Guadeloupe. The employees in Guadeloupe are represented by the Confédération Générale du Travail de Guadeloupe. We have never experienced any labor dispute, strike or work stoppage. We consider our relations with our employees to be satisfactory. We believe our future success will depend on our continuing ability to hire, integrate, and retain qualified personnel.

In the U.S., we currently do not have employees represented by unions recognized by the Company under collective bargaining agreements. However, a union filed a petition with the NLRB seeking to organize the operations and maintenance employees at the Puna complex. A global settlement was reached with the union in February 2016 in which the union withdrew their petition and all issues were settled and closed.

We have no collective bargaining agreements with respect to our Israeli employees. However, by order of the Israeli Ministry of Economy and Industry, the provisions of a collective bargaining agreement between the Histadrut (the General Federation of Labor in Israel) and the Coordination Bureau of Economic Organizations (which includes the Industrialists Association) may apply to some of our Israeli non-managerial, finance and administrative, and sales and marketing personnel. This collective bargaining agreement principally concerns cost of living pay increases, length of the workday, minimum wages and insurance for work-related accidents, annual and other vacation, sick pay, and determination of severance pay, pension contributions, and other conditions of employment. We currently provide such employees with benefits and working conditions, which are at least as favorable as the conditions specified in the collective bargaining agreement.

Insurance

We maintain business interruption insurance, casualty insurance, including flood, volcanic eruption, earthquake and cyber coverage, and primary and excess liability insurance, control of wells, construction all risk, as well as customary worker's compensation and automobile, marine transportation insurance and such other commercial insurance as is generally carried by companies engaged in similar businesses and owning similar properties in the same general areas as us or as may be required by any of our PPAs, leases, financing arrangements, or other contracts. To the extent any such casualty insurance covers both us and/or our power plants, and any other person and/or plants, we generally have specifically designated as applicable solely to us and our power plants "all risk" property insurance coverage in an amount based upon the estimated replacement value of our power plants (provided that earthquake, volcanic eruption and flood coverage may be subject to annual aggregate limits depending on the type and location of the power plant) and business interruption insurance coverage in an amount that also varies from power plant to power plant.

We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries. We hold and maintain a global political risk insurance program for three years covering the significant political risk we identified as described below. This global program is issued by the global lead insurers in the private sector. Currently we hold such insurance for our Zunil, Amatitlan, Olkaria, Platanares and Sarulla operating power plants. Such insurance policies generally cover, subject to the limitations and restrictions contained therein, losses derived from a specified governmental act, such as confiscation, expropriation, riots, and the inability to convert local currency into hard currency and, in certain cases, the breach of agreements with governmental entities, up to approximately 90% of our net equity investment.

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Regulation of the Electric Utility Industry in the United States

The following is a summary overview of the electric utility industry and applicable federal and state regulations and should not be considered a full statement of the law or all issues pertaining thereto.

PURPA

PURPA provides the owners of power plants certain benefits described below if a power plant is a “Qualifying Facility”. A small power production facility is a Qualifying Facility if: (i) the facility does not exceed 80 MW; (ii) the primary energy source of the facility is biomass, waste, renewable resources, or any combination thereof, and at least 75% of the total energy input of the facility is from these sources, and fossil fuel input is limited to specified uses; and (iii) the facility, if larger than one megawatt, has filed with FERC a notice of self-certification of qualifying status, or has filed with FERC an application for FERC certification of qualifying status that has been granted. The 80 MW size limitation, however, does not apply to a facility if (i) it produces electric energy solely by the use, as a primary energy input, of solar, wind, waste or geothermal resources; and (ii) an application for certification or a notice of self-certification of qualifying status of the facility was submitted to FERC prior to December 21, 1994, and construction of the facility commenced prior to December 31, 1999.

FERC's regulations under PURPA exempt owners of small power production Qualifying Facilities that use geothermal resources as their primary source and other Qualifying Facilities that are 30 MW or under in size from regulation under the PUHCA 2005, from many provisions of the FPA and from state laws relating to the financial, organization and rate regulation of electric utilities.

With respect to the FPA, FERC's regulations under PURPA do not exempt from the rate provisions of the FPA sales of energy or capacity from Qualifying Facilities larger than 20 MW in size that are made (a) pursuant to a contract executed after March 17, 2006 that is not a contract made pursuant to a state regulatory authority’s implementation of PURPA or (b) not pursuant to another provision of a state regulatory authority’s implementation of PURPA. The practical effect of these regulations is to require owners of Qualifying Facilities that are larger than 20 MW in size to obtain market-based rate authority from FERC if they seek to sell energy or capacity other than pursuant to a contract executed before March 17, 2006 pursuant to a state regulatory authority’s implementation of PURPA or pursuant to a provision of a state regulatory authority’s implementation of PURPA. Until that contract expires, is terminated or is materially modified, a Qualifying Facility, under a PURPA contract executed prior to March 17, 2006, will not be required to file for authorization to charge for market based rates.

In addition, PURPA and FERC’s regulations under PURPA require that electric utilities offer to purchase electricity generated by Qualifying Facilities at a rate based on the purchasing utility’s incremental cost of purchasing or producing energy (also known as “avoided cost”). However, FERC's regulations under PURPA also allow FERC, upon request of a utility, to terminate a utility’s obligation to purchase energy from Qualifying Facilities upon a finding that Qualifying Facilities have nondiscriminatory access to either: (i) independently administered, auction-based day ahead, and real time markets for energy and wholesale markets for long-term sales of capacity; (ii) transmission and interconnection services provided by a FERC-approved regional transmission entity and administered under an open-access transmission tariff that affords nondiscriminatory treatment to all customers, and competitive wholesale markets that provide a meaningful opportunity to sell capacity and energy, including long and short term sales; or (iii) wholesale markets for the sale of capacity and energy that are at a minimum of comparable competitive quality as markets described in (i) and (ii) above. FERC regulations protect a Qualifying Facility’s rights under any contract or obligation involving purchases or sales that are entered into before FERC has determined that the contracting utility is entitled to relief from the mandatory purchase obligation. FERC has granted the request of California investor-owned utilities for a waiver of the mandatory purchase obligation for Qualifying Facilities larger than 20 MW in size and is currently re-evaluating the 20 MW threshold for such waiver as well as other aspects of its PURPA regulations.

We expect that our power plants in the U.S will continue to meet all of the criteria required for Qualifying Facilities under PURPA. However, since the Heber power plants have PPAs with Southern California Edison that require Qualifying Facility status to be maintained, maintaining Qualifying Facility status remains a key obligation. If any of the Heber power plants loses its Qualifying Facility status our operations could be adversely affected. Loss of Qualifying Facility status would eliminate the Heber power plants’ exemption from the FPA and thus, among other things, the rates charged by the Heber power plants in the PPAs with Southern California Edison and SCPPA would become subject to FERC regulation. Further, it is possible that the utilities that purchase power from the power plants could successfully obtain a waiver of the mandatory-purchase obligation in their service territories. For example, the three California investor-owned utilities have received such a waiver from FERC for projects larger than 20 MW. If this occurs or if FERC reduces the 20 MW threshold or eliminates the mandatory purchase obligation, the power plants’ existing PPAs will not be affected, but the utilities will not be obligated under PURPA to renew or extend these PPAs or execute new PPAs upon the existing PPAs’ expiration, if the size is above the waiver threshold.

PUHCA

Under PUHCA 2005, the books and records of a utility holding company, its affiliates, associate companies, and subsidiaries are subject to FERC and state commission review with respect to transactions that are subject to the jurisdiction of either FERC or the state commission or costs incurred by a jurisdictional utility in the same holding company system. However, if a company is a utility holding company solely with respect to Qualifying Facilities, exempt wholesale generators, or foreign utility companies, it will not be subject to review of books and records by FERC under PUHCA 2005. Qualifying Facilities or exempt wholesale generators that make only wholesale sales of electricity are not subject to state commissions' rate regulations and, therefore, in all likelihood would not be subject to any review of their books and records by state commissions pursuant to PUHCA 2005 as long as the Qualifying Facility is not part of a holding company system that includes a utility subject to regulation in that state.

FPA

Pursuant to the FPA, FERC has exclusive jurisdiction over the rates for most wholesale sales of electricity and transmission in interstate commerce. These rates may be based on a cost of service approach or may be determined on a market basis through competitive bidding or negotiation. FERC's regulations under PURPA exempt owners of small power production Qualifying Facilities that use geothermal resources as their primary source and other Qualifying Facilities that are 30 MW or under in size from many provisions of the FPA. If any of the power plants were to lose its Qualifying Facility status, such power plant could become subject to the full scope of the FPA and applicable state regulations. The application of the FPA and other applicable state regulations to the power plants could require our power plants to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility. Even if a power plant does not lose Qualifying Facility status, if a PPA with a power plant expires, is terminated or is materially modified, the owner of a Qualifying Facility power plant in excess of 20 MW will become subject to rate regulation under the Federal Power Act.

If a power plant in the U.S. were to become subject to FERC's ratemaking jurisdiction under the FPA as a result of loss of Qualifying Facility status and the PPA remains in effect, FERC may determine that the rates currently set forth in the PPA are not just and reasonable and may set rates that are lower than the rates currently charged. In addition, FERC may require that the power plant refund a portion of amounts previously paid by the relevant power purchaser to such power plant. Such events would likely result in a decrease in our future revenues or in an obligation to disgorge revenues previously earned by from the power plant, either of which would have an adverse effect on our revenues.

Moreover, the loss of the Qualifying Facility status of any of our power plants selling energy to Southern California Edison could also permit Southern California Edison, pursuant to the terms of its PPA, to cease taking and paying for electricity from the relevant power plant and to seek refunds for past amounts paid and/or a reduction in future payments. In addition, the loss of any such status would result in the occurrence of an event of default under the indenture for the OFC Senior Secured Notes and the OrCal Senior Secured Notes and hence would give the indenture trustee the right to exercise remedies pursuant to the indenture and the other financing documents.

State Regulation

Our power plants in California and Nevada, by virtue of being Qualifying Facilities that make only wholesale sales of electricity, are not subject to rate, financial and organizational regulations applicable to electric utilities in those states. The power plants each sell or will sell their electrical output under PPAs to electric utilities (Sierra Pacific Power Company, Nevada Power Company, Southern California Edison or SCPPA). All of the utilities except SCPPA are regulated by their respective state public utilities commissions. Sierra Pacific Power Company and Nevada Power Company, which merged and are doing business as NV Energy, are regulated by the PUCN. Southern California Edison is regulated by the CPUC.

Under Hawaii law, non-fossil generators are not subject to regulation as public utilities. Hawaii law provides that a geothermal power producer is to negotiate the rate for its output with the public utility purchaser. If such rate cannot be determined by mutual accord, the PUCH will set a just and reasonable rate. If a non-fossil generator in Hawaii is a Qualifying Facility, federal law applies to such Qualifying Facility and the utility is required to purchase the energy and capacity at its avoided cost. The rates for our power plant in Hawaii are established under a long-term PPA with HELCO.

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Environmental Permits

U.S. environmental permitting regimes with respect to geothermal projects center upon several general areas of focus. The first involves land use approvals. These may take the form of Special Use Permits or Conditional Use Permits from local planning authorities or a series of development and utilization plan approvals and right of way approvals where the geothermal facility is entirely or partly on BLM or U.S. Forest Service lands. Certain federal approvals require a review of environmental impacts in conformance with the federal National Environmental Policy Act. In California, some local permit approvals require a similar review of environmental impacts under a state statute known as the California Environmental Quality Act. These federal and local land use approvals typically impose conditions and restrictions on the construction, scope and operation of geothermal projects.

The second category of permitting focuses on the installation and use of the geothermal wells themselves. Geothermal projects typically have three types of wells: (i) exploration wells designed to define and verify the geothermal resource, (ii) production wells to extract the hot geothermal liquids (also known as brine) for the power plant, and (iii) injection wells to inject the brine back into the subsurface resource. For example, in Nevada and on BLM lands, the well permits take the form of geothermal drilling permits for well installation. Approvals are also required to modify wells, including for use as production or injection wells. For all wells drilled in Nevada, a geothermal drilling permit must be obtained from the Nevada Division of Minerals. Those wells in Nevada to be used for injection will also require Underground Injection Control permits from the Nevada Division of Environmental Protection. Geothermal wells on private lands in California require drilling permits from the California Department of Conservation’s DOGGR. The eventual designation of these installed wells as individual production or injection wells and the ultimate closure of any wells is also reviewed and approved by DOGGR pursuant to a DOGGR-approved Geothermal Injection Program.

A third category of permits involves the regulation of potential air emissions associated with the construction and operation of wells and power plants and surface water discharges associated with construction and operations activities. Generally, each well and plant requires a preconstruction air permit and storm water discharge permit before earthwork can commence. In addition, in some jurisdictions the wells that are to be used for production require and those used for injection may require air emissions permits to operate. Internal combustion engines and other air pollutant emissions sources at the projects may also require air emissions permits. For our projects, these permits are typically issued at the state or county level. Permits are also required to manage storm water during project construction and to manage drilling muds from well construction, as well as to manage certain discharges to surface impoundments, if any.

A fourth category of permits, that are required in both California and Nevada, includes ministerial permits such as building permits, hazardous materials storage and management permits, and pressure vessel operating permits. We are also required to obtain water rights permits in Nevada if water cooling is being used at the power plant. In addition to permits, there are various regulatory plans and programs that are required, including risk management plans (federal and state programs) and hazardous materials management plans (in California).

In some cases our projects may also require permits, issued by the applicable federal agencies or authorized state agencies, regarding threatened or endangered species, permits to impact wetlands or other waters and notices of construction of structures which may have an impact on airspace. Environmental laws and regulations may change in the future, which may modify the time to receive such permits and associated costs of compliance.

As of the date of this report, all of the material environmental permits and approvals currently required for our operating power plants have been obtained. We sometimes experience regulatory delays in obtaining various environmental permits and approvals required for projects in development and construction. These delays may lead to increases in the time and cost to complete these projects. Our operations are designed and conducted to comply with applicable environmental permit and approval requirements. Non-compliance with any such requirements could result in fines and penalties and could also affect our ability to operate the affected project.

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Environmental Laws and Regulations

Our facilities and operations are subject to a number of environmental laws and regulations relating to development, construction and operation. In the U.S, these may include the Clean Air Act, the Clean Water Act, the Emergency Planning and Community Right-to-Know Act, the Endangered Species Act, the National Environmental Policy Act, the Resource Conservation and Recovery Act, and related state laws and regulations.

Our geothermal operations involve significant quantities of brine (substantially, all of which we reinject into the subsurface) and scale, both of which can contain materials (such as arsenic, antimony, lead, and naturally occurring radioactive materials) in concentrations that exceed regulatory limits used to define hazardous waste. We also use various substances, including isopentane and industrial lubricants that could become potential contaminants and are generally flammable. Hazardous materials are also used in our equipment manufacturing operations in Israel. As a result, our projects are subject to domestic and foreign federal, state and local statutory and regulatory requirements regarding the use, storage, fugitive emissions, and disposal of hazardous substances. The cost of investigation and removal or remediation activities associated with a spill or release of such materials could be significant.

Although we are not aware of any mismanagement of these materials, including any mismanagement prior to the acquisition of some of our power plants that has materially impaired any of the power plant sites, any disposal or release of these materials onto the power plant sites, other than by means of permitted injection wells, could lead to contamination of the environment and result in material cleanup requirements or other responsive obligations under applicable environmental laws. We believe that at one time there may have been a gas station located on the Mammoth complex site, but because of significant surface disturbance and construction since that time further physical evaluation of the environmental condition of the former gas station site has been impractical. We believe that, given the subsequent surface disturbance and construction activity in the vicinity of the suspected location of the service station, it is likely that environmental contamination, if any, associated with the former facilities and any associated underground storage tanks would have already been encountered if they still existed.

Regulation Related to New Activity

Our recent entry into the energy storage space and planned provision of energy management, demand response and load shedding services require us to obtain and maintain certain additional authorizations and approvals. These include (1) authorization from FERC to make wholesale sales of power, capacity, and ancillary services at market-based rates, and (2) membership status with eligibility to serve designated contractual functions in the RTOs of PJM, the NYISO, and the ERCOT. In the future, we may need to obtain and maintain similar membership and eligibility status with other RTOs in order to offer such services in their respective areas.

Regulation of the Electric Utility Industry in our Foreign Countries of Operation

The following is a summary overview of certain aspects of the electric industry in the foreign countries in which we have an operating geothermal power plant. As such, it should not be considered a full statement of the laws in such countries or all of the issues pertaining thereto.

Guatemala. The General Electricity Law of 1996, Decree 93-96, created a wholesale electricity market in Guatemala and established a new regulatory framework for the electricity sector. The law created a new regulatory commission, the CNEE, and a new wholesale power market administrator, the AMM, for the regulation and administration of the sector. The AMM is a private not-for-profit entity. The CNEE functions as an independent agency under the Ministry of Energy and Mines and is in charge of regulating, supervising, and controlling compliance with the electricity law, overseeing the market and setting rates for transmission services, and distribution to medium and small customers. All distribution companies must supply electricity to such customers pursuant to long-term contracts with electricity generators. Large customers can contract directly with the distribution companies, electricity generators or power marketers, or buy energy in the spot market. Guatemala has approved a Law of Incentives for the Development of Renewable Energy Power plants, Decree 52-2003, in order to promote the development of renewable energy power plants in Guatemala. This law provides certain benefits to companies utilizing renewable energy, including a 10-year exemption from corporate income tax and VAT on imports and customs duties. On September 16, 2008, CNEE issued a resolution which approved the Technical Norms for the Connection, Operation, Control and Commercialization of the Renewable Distributed Generation and Self-producers Users with Exceeding Amounts of Energy. This Technical Norm was created to regulate all aspects of generation, connection, operation, control and commercialization of electric energy produced with renewable sources to promote and facilitate the installation of new generation plants, and to promote the connection of existing generation plants which have exceeding amounts of electric energy for commercialization. It is applicable to projects with a capacity of up to 5 MW. At present, the General Electricity Law and the Law of Incentives for the Development or Renewable Energy Power Plants are still in force.

Kenya. The electric power sector in Kenya is regulated by the Kenyan Energy Act. Among other things, the Kenyan Energy Act provides for the licensing of electricity power producers and public electricity suppliers or distributors. KPLC is the only licensed public electricity supplier and has a virtual monopoly in the distribution of electricity in the country. The Kenyan Energy Act permits IPPs to install power generators and sell electricity to KPLC, which is owned by various private and government entities, and which currently purchases energy and capacity from other IPPs in addition to our Olkaria III complex. The electricity sector is regulated by the ERC which was created under the Kenyan Energy Act. KPLC's retail electricity rates are subject to approval by the ERC. The ERC has an expanded mandate to regulate not just the electric power sector but the entire energy sector in Kenya. Transmission of electricity is now undertaken by KETRACO while another company, GDC, is responsible for geothermal assessment, drilling of wells and sale of steam for electricity operations to IPPs and KenGen. Both KETRACO and GDC are wholly owned by the government of Kenya. Under the new national constitution enacted in August 2010, formulation of energy policy (including electricity) and energy regulation are functions of the national government. However, the constitution lists the planning and development of electricity and energy regulation as a function of the county governments (i.e. the regional or local level where an individual power plant is or is intended to be located).

Indonesia. The 2009 Electricity Law divided the power business into two broad categories: (1) activities that supply electrical power, both public supply and captive supply (own use), such as electrical power generation, electrical power transmission, electrical power distribution and the sale of electrical power and (2) the activities involved in electrical power support such as service businesses (consulting, construction, installation, operation & maintenance, certification & training, testing etc.) and industry businesses (power tools & power equipment supply). The power generation is dominated by PLN (state owned company) which controls around 70% of generating assets in Indonesia. Private sector participation is allowed through IPPs arrangement. IPP appointment is most often through tender although IPPs can be directly appointed or selected. The law provides PLN with priority rights to conduct its business throughout Indonesia. As the sole owner of transmission and distribution assets, PLN remains the only business entity involved in transmitting and distributing although the Law allows for private participation. While the 2014 Geothermal Law endorses private participation as Geothermal IPP, the Geothermal IPP appointment is through tender held by the Central Government. The Central Government also awards the tender winner a Geothermal License. Accordingly, the Geothermal License holder will conduct exploration and feasibility studies within five years subject to two one-year extensions, conduct well development and power plant construction and sell the electricity generated to PLN for a maximum of 30 years. Prior to the expiration of the Geothermal License, the IPP can propose to extend for another 20 years. Starting in 2017, the regulatory framework with respect to tariffs is based on PLN's existing average cost of generation (known by its Indonesian acronym, BPP) with respect to the relevant local grid and excludes transmission and distribution costs. The Minister of Energy releases each year a list of local BPPs and the national BPP (which is an average of the local BPPs). The BPPs for a particular year are based on PLN's previous year audited generation costs. For 2017, the national BPP was set at Rp 983 (equivalent to US$ cent 7.39/kWh at Rp 13,307/US$) based on PLN's 2016 audited generation costs. For geothermal, the tariff is measured as follows: (i) if the local BPP is higher than the national BPP, the maximum tariff is the local BPP, (ii) if the local BPP is lower than or the same as the national BPP, the tariff is based on mutual agreement between PLN and the IPP.

Guadeloupe. EDF is the transmission and distribution utility in Guadeloupe and also operates a significant portion of Guadeloupe's fossil energy generation. There are also a number of IPPs in Guadeloupe, primarily producing renewable electricity. The electricity sector in Guadeloupe is regulated by the Commission Regulation of Energy (CRE), which also regulates EDF's operations in mainland France and its other overseas territories. The electricity sector in Guadeloupe is characterized by both enabling features and obstacles with respect to renewable energy. One of the most influential enabling features is a French law requiring the utility to purchase power from any interconnected renewable generator. The major obstacle preventing further uptake of renewable electricity generation is the cap on variable generation at 30% of instantaneous system load.

Honduras. In 2014, Honduras approved its new Law of Electrical Industry (Decree 404-2013), which provides the legal framework for the electricity sector and replaces the previous Electricity Subsector Framework Law (Decree 158 of 1994, regulated by Accord 934 of 1997). The Law establishes technology-specific auctions for renewable energy. It creates the Regulatory Commission of Electric Power (CREE) as the entity in charge of supervising the bidding processes and the awarding of PPAs. The CREE is also responsible for granting study permits for the construction of generation projects that use renewable natural resources. Permits will have a maximum duration of two years, and will be revoked if no studies have been initiated within a period of six months and the reports required by the CREE have not been submitted. The new Law also establishes that all new capacity must be contracted through auctions and that the government can set a minimum quota for renewables in each auction. With respect to metering, after previous regulation applied legal incentives to renewable energy metering, the new law mandates utilities to buy excess power and credit it towards monthly bills and to install bi-directional meters.

Among others, the objectives of the law are to adapt the electricity sector's legislation to the Framework Treaty for the Central American Electricity Market, which Honduras is a party to, and update the operating rules in the country's electricity industry by incorporating structures and modern practices to increase the sector's efficiency and competency in the production and marketing of electricity services.

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With the passage of this new law, Honduras is moving into a new and open market. Under this legislation, all aspects of the market have been opened to private parties. This legislation is still being implemented within the market.

Honduras has also approved a Law of Incentives for Renewable Energy Projects, Decree 70-2007, further amended by Decree 138-2013, with additional incentives to solar PV projects, etc. The purpose, as in other countries of the region, is to promote the development of renewable energy power plants. Laws provide certain benefits to companies that generate power through renewable sources, including a 10-year exemption from corporate income tax and VAT on imports and customs duties, a fast track process for certain permits and a Sovereign Guaranty by the Central Government for the payments of the off-taker, the Public Utility Company, ENEE. At present, the Law of the Electrical Industry and the Laws of Incentives for Renewable Energy Projects are still in force.

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ITEM 1A. RISK FACTORS

Because of the following factors, as well as other variables affecting our business, operating results or financial condition, past financial performance may not be a reliable indicator of future performance, and historical trends should not be used to anticipate results or trends in future periods.

Concentration of customers may expose us to heightened financial exposure.

We often rely on single customers at our facilities, exposing such facilities to financial risks if any customer should fail to perform its obligations.

Our businesses often rely on a single customer to purchase all or a significant portion of a facility's output. The financial performance of these facilities depends on such customer continuing to perform its obligations under the long-term agreement. A facility's financial results could be materially and adversely affected if any of our customer fails to fulfill its contractual obligations and we are unable to find other customers to produce the same level of profitability. We cannot assure that such performance failures by third parties will not occur, or that if they do occur, such failures will not adversely affect the cash flows or profitability of our businesses.

For example, we are exposed to the credit and financial condition of SCPPA and its municipal utility members, as customers that buy the output from six of our geothermal power plant. Because our contracts with SCPPA are long-term, we may be adversely affected if the credit quality of any of these customers were to decline or if their respective financial conditions were to deteriorate or if they are otherwise unable to perform their obligations under our long-term contracts.

A significant portion of our Product segment revenues are concentrated in one region and expose us to regional economic or market declines.

A significant portion of our Product segment revenues are concentrated in Turkey and rely on the continued geothermal development growth and government support for geothermal development in the country. Adverse political developments in the relationship between Turkey and the U.S., adverse economic developments in this region or a decline in government support for the development of geothermal power in the country could materially and adversely affect regional demand for the geothermal equipment and services we provide in the Turkish market or the prices we may charge for such equipment and services, which in turn could materially and adversely affect our Product segment profit margins and, consequently, our business, financial condition, future results and cash flows.

Our financial performance depends on the successful operation of our geothermal power and REG plants, which is subject to various operational risks.

Our financial performance depends on the successful operation of our subsidiaries' geothermal and REG power plants. In connection with such operations, we derived approximately 67.6% of our total revenues for the year ended December 31, 2017 from the sale of electricity. The cost of operation and maintenance and the operating performance of our subsidiaries' geothermal power and REG plants may be adversely affected by a variety of factors, including some that are discussed elsewhere in these risk factors and the following:

regular and unexpected maintenance and replacement expenditures;

shutdowns due to the breakdown or failure of our equipment or the equipment of the transmission serving utility;

labor disputes;

the presence of hazardous materials on our power plant sites;

continued availability of cooling water supply;

- catastrophic events such as fires, explosions, earthquakes, volcanic activity, landslides, floods, releases of hazardous materials, severe weather storms, or similar occurrences affecting our power plants or any of the power purchasers or other third parties providing services to our power plants; and

- the aging of power plants (which may reduce their availability and increase the cost of their maintenance).

Any of these events could significantly increase the expenses incurred by our power plants or reduce the overall generating capacity of our power plants and could significantly reduce or entirely eliminate the revenues generated by one or more of our power plants, which in turn would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

As mentioned above, the aging of our power plants may reduce their availability and increase maintenance costs due to the need to repair or replace our equipment.

Our exploration, development, and operation of geothermal energy resources are subject to geological risks and uncertainties, which may result in decreased performance or increased costs for our power plants.

Our primary business involves the exploration, development, and operation of geothermal energy resources. These activities are subject to uncertainties that, in certain respects, are similar to those typically associated with oil and gas exploration, development, and exploitation, such as dry holes, uncontrolled releases, and pressure and temperature decline. Any of these uncertainties may increase our capital expenditures and our operating costs, or reduce the efficiency of our power plants. We may not find geothermal resources capable of supporting a commercially viable power plant at exploration sites where we have conducted tests, acquired land rights, and drilled test wells, which would adversely affect our development of geothermal power plants. Further, since the commencement of their operations, several of our power plants have experienced geothermal resource cooling, uncontrolled flow and/or reservoir pressure decline in the normal course of operations. Because geothermal reservoirs are complex geological structures, we can only estimate their geographic area and sustainable output. The viability of geothermal power plants depends on different factors directly related to the geothermal resource (such as the temperature, pressure, storage capacity, transmissivity, and recharge) as well as operational factors relating to the extraction or reinjection of geothermal fluids. For example, at our North Brawley power plant, instability of the sands and clay in the geothermal resource and variability in the chemical composition of the geothermal fluid have all combined to increase our capital expenditures for the plant, as well as our ongoing operating expenses, and have so far prevented the plant from operation at its intended design capacity. Another example is the Sarulla project, where we are both an equity investor and equipment supplier, which has experienced delays and budget cost overruns in the drilling program. Our geothermal energy power plants may also suffer an unexpected decline in the capacity of their respective geothermal wells and are exposed to a risk of geothermal reservoirs not being sufficient for sustained generation of the electrical power capacity desired over time.

Another aspect of geothermal operations is the management and stabilization of subsurface impacts caused by fluid injection pressures of production and injection fluids to mitigate subsidence. In the case of the geothermal resource supplying the Heber complex, pressure drawdown in the center of the well field has caused some localized ground subsidence, while pressure in the peripheral areas has caused localized ground inflation. Inflation and subsidence, if not controlled, can adversely affect farming operations and other infrastructure at or near the land surface. Potential costs, which cannot be estimated and may be significant, of failing to stabilize site pressures in the Heber complex area include repair and modification of gravity-based farm irrigation systems and municipal sewer piping and possible repair or replacement of a local road bridge spanning an irrigation canal.

Additionally, active geothermal areas, such as the areas in which our power plants are located, are subject to frequent low-level seismic disturbances, volcanic eruptions and lava flows. Serious seismic disturbances, volcanic eruptions and lava flows are possible and could result in damage to our power plants (or transmission lines used by customers who buy electricity from us) or equipment or degrade the quality of our geothermal resources to such an extent that we could not perform under the PPA for the affected power plant, which in turn could reduce our net income and materially and adversely affect our business, financial condition, future results and cash flow. If we suffer a serious seismic disturbance, volcanic eruptions and lava flows, our business interruption and property damage insurance may not be adequate to cover all losses sustained as a result thereof. In addition, insurance coverage may not continue to be available in the future in amounts adequate to insure against such seismic disturbances, volcanic eruptions and lava flows.

Furthermore, absent additional geologic/hydrologic studies, any increase in power generation from our geothermal power plants, failure to reinject the geothermal fluid or improper maintenance of the hydrological balance may affect the operational duration of the geothermal resource and cause it to decline in value over time, and may adversely affect our ability to generate power from the relevant geothermal power plant.

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Reduced levels of recovered energy required for the operation of our REG power plants may result in decreased performance of such power plants.

Our REG power plants generate electricity from recovered energy or so-called "waste heat" that is generated as a residual by-product of gas turbine-driven compressor stations and a variety of industrial processes. Any interruption in the supply of the recovered energy source, such as a result of reduced gas flows in the pipelines or reduced level of operation at the compressor stations, or in the output levels of the various industrial processes, may cause an unexpected decline in the capacity and performance of our recovered energy power plants.

Our business development activities may not be successful and our projects under construction may not commence operation as scheduled.

We are in the process of developing and constructing a number of new power plants. Our success in developing a particular project is contingent upon, among other things, negotiation of satisfactory engineering and construction agreements and obtaining PPAs and transmission services agreements, receipt of required governmental permits, obtaining adequate financing, and the timely implementation and satisfactory completion of field development, testing and power plant construction and commissioning. We may be unsuccessful in accomplishing any of these matters or doing so on a timely basis. Although we may attempt to minimize the financial risks attributable to the development of a project by securing a favorable PPA and applicable transmission services agreements, obtaining all required governmental permits and approvals and arranging, in certain cases, adequate financing prior to the commencement of construction, the development of a power project may require us to incur significant expenses for preliminary engineering, permitting and legal and other expenses before we can determine whether a project is feasible, economically attractive or capable of being financed.

Currently, we have geothermal projects and prospects under exploration, development or construction in the U.S., Kenya, Guatemala, Guadeloupe, New Zealand, Honduras, Indonesia and Ethiopia, and we intend to pursue the expansion of some of our existing plants and the development of other new plants. Our completion of these facilities is subject to substantial risks, including:

- inability to secure a PPA;
- inability to secure transmission services agreements;
- inability to secure the required financing;

- cost increases and delays due to unanticipated shortages of adequate resources to execute the project such as equipment, material and labor;
- work stoppages resulting from force majeure event including riots, strikes and whether conditions;
- inability to obtain permits, licenses and other regulatory approvals;
- failure to secure sufficient land positions for the wellfield, power plant and rights of way;
- failure by key contractors and vendors to timely and properly perform, including where we use equipment manufactured by others;
- failure by key suppliers to provide steam for electricity generation, including at the Menengai project in Kenya.
- inability to secure or delays in securing the required transmission line and/or capacity;
- adverse environmental and geological conditions (including inclement weather conditions);
- adverse local business law; and
- our attention to other projects and activities, including those in the solar energy and energy storage sectors.

Any one of these could give rise to delays, cost overruns, the termination of the plant expansion, construction or development or the loss (total or partial) of our interest in the project under development, construction, or expansion.

We rely on power transmission facilities that we do not own or control.

We depend on transmission facilities owned and operated by others to deliver the power we sell from our power plants to our customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver power to our customers may be adversely impacted and we may either incur additional costs or forego revenues. In addition, lack of access to new transmission capacity may affect our ability to develop new projects. Existing congestion of transmission capacity, as well as expansion of transmission systems and competition from other developers seeking access to expanded systems, could also affect our performance.

We may be unable to obtain the financing we need to pursue our growth strategy and any future financing we receive may be less favorable to us than our current financing arrangements, either of which may adversely affect our ability to expand our operations.

Most of our geothermal power plants generally have been financed using leveraged financing structures, consisting of non-recourse or limited recourse debt obligations. Each of our projects under development or construction and those projects and businesses we may seek to acquire or construct will require substantial capital investment. Our continued access to capital on acceptable terms is necessary for the success of our growth strategy. Our attempts to obtain future financings may not be successful or on favorable terms**.**

Market conditions and other factors may not permit future project and acquisition financings on terms similar to those our subsidiaries have previously received. Our ability to arrange for financing on a substantially non-recourse or limited recourse basis, and the costs of such financing, are dependent on numerous factors, including general economic conditions, conditions in the global capital and credit markets, investor confidence, the continued success of current power plants, the credit quality of the power plants being financed, the political situation in the country where the power plant is located, and the continued existence of tax and securities laws which are conducive to raising capital. If we are not able to obtain financing for our power plants on a substantially non-recourse or limited recourse basis, we may have to finance them using recourse capital such as direct equity investments or the incurrence of additional debt by us.

Also, in the absence of favorable financing options, we may decide not to build new plants or acquire facilities from third parties. Any of these alternatives could have a material adverse effect on our growth prospects.

We may also need additional financing to implement our strategic plan. For example, our cash flow from operations and existing liquidity facilities may not be adequate to finance any acquisitions we may want to pursue or new technologies we may want to develop or acquire. Financing for acquisitions or technology development activities may not be available on the non-recourse or limited recourse basis we have historically used for our business, or on other terms we find acceptable.

Our use of joint ventures may limit our flexibility with jointly owned investments.

We have sold minority equity interests in four of our consolidated subsidiaries, through which we hold a large number of our domestic geothermal power plants and recovered energy generation plants, to different third parties and we have partners that hold a minority equity interest in our geothermal power plant in Guadeloupe. We may continue in the future to develop and/or acquire and/or hold properties in joint ventures with other entities when circumstances warrant the use of these structures. Ownership of assets in joint ventures is subject to risks that may not be present with other methods of ownership, including:

- we could experience an impasse on certain decisions because we do not have sole decision-making authority, which could require us to expend additional resources on resolving such impasses or potential disputes, including litigation or arbitration;

- our joint venture partners could have investment goals that are not consistent with our investment objectives, including the timing, terms and strategies for any investments in the projects that are owned by the joint ventures, which could affect decisions about future capital expenditures, major operational expenditures and retirement of assets, among other things;

- our ability to transfer our interest in a joint venture to a third party may be restricted and the market for our interest may be limited;

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- our joint venture partners may be structured differently than us for tax purposes, and this could impact our ability to fully take advantage of federal tax incentives available for renewable energy projects;

- our joint venture partners might become bankrupt, fail to fund their share of required capital contributions or fail to fulfill their obligations as a joint venture partner, which may require us to infuse our own capital into the venture on behalf of the partner despite other competing uses for such capital; and

- our joint venture partners may have competing interests in our markets and investments in companies that compete directly or indirectly with us that could create conflict of interest issues.

Our international operations expose us to risks related to the application of foreign laws, taxes, economic conditions, labor supply and relations, political conditions, and policies of foreign governments, any of which may adversely affect our business, financial condition, future results and cash flow.

We have substantial operations outside of the U.S., both in our Electricity segment and our Product segment. Our foreign operations are subject to regulation by various foreign governments and regulatory authorities and are subject to the application of foreign laws. Such foreign laws or regulations may not provide the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to our operations in the U.S., which may adversely affect our ability to receive revenues or enforce our rights in connection with our foreign operations. Furthermore, existing laws or regulations may be amended or repealed, and new laws or regulations may be enacted or issued. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the power plants that we may develop or acquire, thus limiting our ability to control the development, construction and operation of such power plants, or our ability to import our products into such countries. Our foreign operations are also subject to significant political, economic and financial risks, which vary by country, and include:

- changes in government policies or personnel;

- changes in general economic conditions;

- restrictions on currency transfer or convertibility;

- changes in labor relations;

- political instability and civil unrest;

- changes in the local electricity and/or geothermal markets;

- breach or repudiation of important contractual undertakings by governmental entities; and

- expropriation and confiscation of assets and facilities.

In particular, with respect to our Electricity segment, in Guatemala the electricity sector was partially privatized, and it is currently unclear whether further privatization will occur in the future. Such developments may affect our Amatitlan and Zunil power plants if, for example, they result in changes to the prevailing tariff regime or in the identity and creditworthiness of our power purchasers. In Kenya, any break-up or potential privatization of KPLC, the power purchase for our power plants located in Kenya, may adversely affect our Olkaria III complex. Although we generally obtain political risk insurance in connection with our foreign power plants, such political risk insurance does not mitigate all of the above-mentioned risks. In addition, insurance proceeds received pursuant to our political risk insurance policies, where applicable, may not be adequate to cover all losses sustained as a result of any covered risks and may at times be pledged in favor of the power plant lenders as collateral. Also, insurance may not be available in the future with the scope of coverage and in amounts of coverage adequate to insure against such risks and disturbances.

With respect to our Product segment, since we primarily engage in sales in those markets where there is a geothermal reservoir, any such change might adversely affect geothermal developers in those markets and, subsequently, the ability of such developers to purchase our products. In Turkey, we are involved as a major equipment supplier in a significant number of projects that are currently under construction. We have faced, and anticipate that we will continue to face, obstacles in the Turkish market that may materially and adversely affect our future business and operations in Turkey, including the recent failed coup, devaluation of the Turkish Lira, a general slowdown in the Turkish economy and an inability to obtain project and bank financing on terms acceptable to us, together with political uncertainties, all of which are causing our cost of revenues in Turkey to increase.

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Any or all of the changes discussed above could materially and adversely affect our business, financial condition, future results and cash flow.

Our foreign power plants and foreign manufacturing operations expose us to risks related to fluctuations in currency rates, which may reduce our profits from such power plants and operations.

Risks attributable to fluctuations in currency exchange rates can arise when 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. In addition, the imposition by foreign governments of restrictions on the transfer of foreign currency abroad, or restrictions on the conversion of local currency into foreign currency, would have an adverse effect on the operations of our foreign power plants and foreign manufacturing operations, and may limit or diminish the amount of cash and income that we receive from such foreign power plants and operations.

A significant portion of our electricity revenues is attributed to payments made by power purchasers under PPAs. The failure of any such power purchaser to perform its obligations under the relevant PPA or the loss of a PPA due to a default would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

A significant portion of our revenues is attributable to electricity our power plants sell to power purchasers under the relevant PPAs. There is a risk that any one or more of the power purchasers may not fulfill their respective payment obligations under their PPAs. If any of the power purchasers fails to meet its payment obligations under its PPA(s), such failure could materially and adversely affect our business, financial condition, future results and cash flow.

Storage projects that we are currently developing or plan to develop in the future may operate as "merchant" facilities without long-term power sales agreements for some or all of their generating capacity and output and therefore such projects will be exposed to market fluctuations.

Storage projects that we are currently developing or plan to develop in the future may operate as "merchant" facilities without long-term sales agreements for some or all of their generating capacity and output and therefore such projects will be exposed to market fluctuations. Without the benefit of long-term sales agreements for these assets, we cannot be sure that we will be able to sell any or all of the power and ancillary services generated by these facilities at commercially attractive rates or that these facilities will be able to operate profitably. This could lead to future impairments of our property, plant and equipment or to the closing of certain of our storage facilities, resulting in economic losses and liabilities, which could have a material adverse effect on our results of operations, financial condition or cash flows.

Seasonal variations may cause fluctuations in our cash flows, which may cause the market price of our common stock to fall in certain periods.

Our results of operations are subject to seasonal variations. This is primarily because some of our power plants may experience reduced generation during warm periods due to the lower heat differential between the geothermal fluid and the ambient surroundings. Some of our domestic power plants receive higher capacity payments under the relevant PPAs during the summer months, and due to the generally higher time-of-use energy factor during the summer months. Such seasonal variations could materially and adversely affect our business, financial condition, future results and cash flow. If our operating results fall below the public’s or analysts’ expectations in some future period or periods, the market price of our common stock will likely fall in such period or periods.

Pursuant to the terms of some of our PPAs with investor-owned electric utilities and publicly-owned electric utilities in states that have renewable portfolio standards, the failure to supply the contracted capacity and energy thereunder may result in the imposition of penalties.

Pursuant to the terms of certain of our PPAs, we may be required to make payments to the relevant power purchaser under certain conditions, such as shortfall in delivery of renewable energy and energy credits, and not meeting certain performance threshold requirements, as defined in the relevant PPA. The amount of payment required is dependent upon the level of shortfall in delivery or performance requirements and is recorded in the period the shortfall occurs. In addition, if we do not meet certain minimum performance requirements, the capacity of the relevant power plant may be permanently reduced. Any or all of these considerations could materially and adversely affect our business, financial condition, future results and cash flow.

The Energy Choice Initiative (ECI), a pending amendment to the Constitution of the State of Nevada, may permit our customer to terminate its PPAs with us.

The ECI is a proposed amendment to the Constitution of the State of Nevada that would require the Nevada Legislature to adopt new statutes or amend existing statutes in order to establish an open and competitive retail electricity market and prevent the concentration of the electricity generation market among only a few generators of electricity. This ballot question passed with over 72% of Nevada voters in favor in November 2016, and if it passes again in November 2018, the Nevada Legislature will be required to amend state law in the manner described above by no later than 2023.

It is unclear what impact the ECI would have on our existing PPAs and the Nevada RPS. NV Energy, the offtaker of our Brady, SB Complex, Tuscarora, Jersey Valley and McGinness Hills power plants, is taking the position that the ECI would require the termination of our existing PPAs and potentially the termination of the RPS. Whether existing PPAs could be terminated will remain unclear until the scope of the Nevada Legislature's implementation of the ECI becomes known. If the Nevada Legislature adopts any new laws pursuant to the ECI that terminate or require the termination of, our existing PPAs with NV Energy, we could lose significant amounts of revenue derived from the sale of electricity to NV Energy under such PPAs which could materially and adversely affect our business, financial condition, future results and cash flow.

The SRAC for our power purchasers may decline, which would reduce our power plant revenues and could materially and adversely affect our business, financial condition, future results and cash flow.

Under two of the PPAs for our power plants in California, the price that Southern California Edison pays is based upon its SRAC, which are the incremental costs that it would have incurred had it generated the relevant electricity itself or purchased such electricity from others. Under settlement agreements between Southern California Edison and a number of power generators in California that are Qualifying Facilities, including our subsidiaries, the energy price component payable by Southern California Edison was fixed through April 2012, but since then is based on Southern California Edison's SRAC, as determined by the CPUC. The SRAC may vary substantially on a monthly basis, and are expected to be based primarily on natural gas prices for gas delivered to California as well as other factors. The levels of SRAC prices paid by Southern California Edison may decline following the expiration date of the settlement agreements, which in turn would reduce our power plant revenues derived from Southern California Edison under our PPAs and could materially and adversely affect our business, financial condition, future results and cash flow.

Under the terms of a global settlement approved by CPUC (Global Settlement) SRAC for our Heber 2 and Mammoth G2 PPAs are tied to a formula with energy market heat rates. The Global Settlement further provides that after July 1, 2015 if the term of any of the PPAs we have for these power plants expires, Southern California Edison would have no obligation to purchase power from any of these plants that has a generating capacity in excess of 20 MW, which would apply to the PPAs for our Heber 2 power plant (37 MW contract capacity) with Southern California Edison.

Our Mammoth G2 plant (10.5 MW contract capacity) will be entitled to a new standard offer PPA, with SRAC pricing and capacity payments as determined from time to time by the CPUC. The joint parties to the Global Settlement agreed that the utilities can request from FERC a waiver of the mandatory purchase obligation under PURPA for Qualifying Facilities above 20 MW and FERC has granted such waiver for these California utilities.

If any of our domestic power plants loses its current Qualifying Facility status under PURPA, or if amendments to PURPA are enacted that substantially reduce the benefits currently afforded to Qualifying Facilities, our domestic operations could be adversely affected.

Most of our domestic power plants are Qualifying Facilities pursuant to PURPA, which largely exempts the power plants from the FPA, and certain state and local laws and regulations regarding rates and financial and organizational requirements for electric utilities.

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If any of our domestic power plants were to lose its Qualifying Facility status, such power plant could become subject to the full scope of the FPA and applicable state regulation. The application of the FPA and other applicable state regulation to our domestic power plants could require our operations to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility.

If a domestic power plant were to lose its Qualifying Facility status, it would become subject to full regulation as a public utility under the FPA, and the rates charged by such power plant pursuant to its PPAs would be subject to the review and approval of FERC. FERC, upon such review, may determine that the rates currently set forth in such PPAs are not appropriate and may set rates that are lower than the rates currently charged. In addition, FERC may require that the affected domestic power plant refund amounts previously paid by the relevant power purchaser to such power plant. Even if a power plant does not lose its Qualifying Facility status, pursuant to regulations issued by FERC for Qualifying Facility power plants above 20 MW, if a power plant's PPA is terminated or otherwise expires, and the subsequent sales are not made pursuant to a state's implementation of PURPA, that power plant will become subject to FERC's ratemaking jurisdiction under the FPA. Moreover, a loss of Qualifying Facility status also could permit the power purchaser, pursuant to the terms of the particular PPA, to cease taking and paying for electricity from the relevant power plant or, consistent with FERC precedent, to seek refunds of past amounts paid. This could cause the loss of some or all of our revenues payable pursuant to the related PPAs, result in significant liability for refunds of past amounts paid, or otherwise impair the value of our power plants. If a power purchaser were to cease taking and paying for electricity or seek to obtain refunds of past amounts paid, there can be no assurance that the costs incurred in connection with the power plant could be recovered through sales to other purchasers or that we would have sufficient funds to make such payments. In addition, the loss of Qualifying Facility status would be an event of default under the financing arrangements currently in place for some of our power plants, which would enable the lenders to exercise their remedies and enforce the liens on the relevant power plant.

Pursuant to the Energy Policy Act of 2005, FERC also has the authority to prospectively lift the mandatory obligation of a utility under PURPA to offer to purchase the electricity from a Qualifying Facility if the utility operates in a workably competitive market. Our existing PPAs between a Qualifying Facility and a utility are not affected. If, in addition to the California utilities' waiver of the mandatory purchase obligation for QF projects that exceed 20 MW described in the risk factor above, the utilities in the other 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 the power plant in the region under Federal law upon termination of the existing PPA or with respect to new power plants, which could materially and adversely affect our business, financial condition, future results and cash flow. Moreover, FERC has the authority to modify its regulations relating to the utility's mandatory purchase obligation under PURPA, which could result in the reduction in the purchase obligation of California and other utilities to a level below 20 MW, or the elimination of the purchase obligation. If that were to occur it could materially and adversely affect our business, financial condition, future results and cash flow.

The reduction or elimination of government incentives could adversely affect our business, financial condition, future results and cash flows.

Construction and operation of our geothermal power plants and recovered energy-based power plants has benefited, and may benefit in the future, from public policies and government incentives that support renewable energy and enhance the economic feasibility of these projects in regions and countries where we operate. Such policies and incentives include PTCs and ITCs, accelerated depreciation tax benefits, renewable portfolio standards, carbon trading mechanisms, rebates, and mandated feed-in-tariffs, and may include similar or other incentives to end users, distributors, system integrators and manufacturers of geothermal, solar and other power products. Some of these measures have been implemented at the federal level, while others have been implemented by different states within the U.S. or countries outside the U.S. where we operate.

The availability and continuation of these public policies and government incentives have a significant effect on the economics and viability of our development program and continued construction of new geothermal, recovered energy-based, Solar PV power plants and, recently, energy storage projects. Any changes to such public policies, or any reduction in or elimination or expiration of such government incentives could affect us in different ways. For example, any reduction in, termination or expiration of renewable portfolio standards may result in less demand for generation from our geothermal and recovered energy-based, power plants. Any reductions in, termination or expiration of other government incentives could reduce the economic viability of, and cause us to reduce, the construction of new geothermal, recovered energy-based, Solar PV or any other power plants. Similarly, any such changes that affect the geothermal energy industry in a manner that is different from other sources of renewable energy, such as wind or solar, may put us at a competitive disadvantage compared to businesses engaged in the development, construction and operation of renewable power projects using such other resources. Any of the foregoing outcomes could have a material adverse effect on our business, financial condition, future results, and cash flows.

Our financial performance could be adversely affected by changes in the legal and regulatory environment affecting our power plants.

All of our power plants are subject to extensive regulation, and therefore changes in applicable laws or regulations, or interpretations of those laws and regulations, could result in increased compliance costs, the need for additional capital expenditures or the reduction of certain benefits currently available to our power plants. The structure of domestic and foreign federal, state and local energy regulation currently is, and may continue to be, subject to challenges, modifications, the imposition of additional regulatory requirements, and restructuring proposals. We or our power purchasers may not be able to obtain all regulatory approvals that may be required in the future, or any necessary modifications to existing regulatory approvals, or maintain all required regulatory approvals. In addition, the cost of operation and maintenance and the operating performance of geothermal power plants may be adversely affected by changes in certain laws and regulations, including tax laws.

Any changes to applicable laws and regulations could significantly increase the regulatory-related compliance and other expenses incurred by the power plants and could significantly reduce or entirely eliminate the revenues generated by one or more of the power plants, which in turn would reduce our net income and could materially and adversely affect our business, financial condition, future results and cash flow.

The costs of compliance with environmental laws and of obtaining and maintaining environmental permits and governmental approvals required for construction and/or operation may increase in the future and these costs (as well as any fines or penalties that may be imposed upon us in the event of any non-compliance with such laws or regulations) could materially and adversely affect our business, financial condition, future results and cash flow.

Environmental laws, ordinances and regulations affecting us can be subject to change and such change could result in increased compliance costs, the need for additional capital expenditures, or otherwise adversely affect us. In addition, our power plants are required to comply with numerous domestic and foreign, federal, regional, state and local statutory and regulatory environmental standards and to maintain numerous environmental permits and governmental approvals required for construction and/or operation. We may not be able to renew, maintain or obtain all environmental permits and governmental approvals required for the continued operation or further development of the power plants. We have not yet obtained certain permits and government approvals required for the completion and successful operation of power plants under construction or enhancement. Our failure to renew, maintain or obtain required permits or governmental approvals, including the permits and approvals necessary for operating power plants under construction or enhancement, could cause our operations to be limited or suspended. Finally, some of the environmental permits and governmental approvals that have been issued to the power plants contain conditions and restrictions, including restrictions or limits on emissions and discharges of pollutants and contaminants, or may have limited terms. If we fail to satisfy these conditions or comply with these restrictions, or with any statutory or regulatory environmental standards, we may become subject to regulatory enforcement action and the operation of the power plants could be adversely affected or be subject to fines, penalties or additional costs.

We could be exposed to significant liability for violations of hazardous substances laws because of the use or presence of such substances at our power plants.

Our power plants are subject to numerous domestic and foreign federal, regional, state and local statutory and regulatory standards relating to the use, storage and disposal of hazardous substances. We use butane, pentane, industrial lubricants, and other substances at our power plants which are or could become classified as hazardous substances. If any hazardous substances are found to have been released into the environment at or by the power plants in concentrations that exceed regulatory limits, we could become liable for the investigation and removal of those substances, regardless of their source and time of release. If we fail to comply with these laws, ordinances or regulations (or any change thereto), we could be subject to civil or criminal liability, the imposition of liens or fines, and large expenditures to bring the power plants into compliance. Furthermore, in the U.S., we can be held liable for the cleanup of releases of hazardous substances at other locations where we arranged for disposal of those substances, even if we did not cause the release at that location. The cost of any remediation activities in connection with a spill or other release of such substances could be significant.

We believe that at one time there may have been a gas station located on the Mammoth complex site, but because of significant surface disturbance and construction since that time, further physical evaluation of the environmental condition of the former gas station site has been impractical. There may be soil or groundwater contamination and related potential liabilities of which we are unaware related to this site, which may be significant and could materially and adversely affect our business, financial condition, future results and cash flow.

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We may decide not to implement, or may not be successful in implementing, one or more elements of our multi-year strategic plan, and the plan as implemented may not achieve its goal to enhance shareholder value through long-term growth of the Company

We adopted a multi-year strategic plan to:

- expand our geographical base;
- expand into new technologies, such as energy storage and solar PV electric power generation both in large "utility scale" projects and smaller C&I projects for commercial, industrial, governmental, educational and other institutional customers; and
- expand our customer base.

There are uncertainties and risks associated with the plan, both as to implementation and outcome. Implementation of the plan may be affected by a number of factors, including that:

- we are still developing some elements of the plan and evaluating how and when some elements of the plan will be implemented;
- we may decide to change, or not implement, one or more elements of the plan over time; and
- we may not be successful in implementing one or more elements of the plan, in each case for a number of reasons.

For example, we may face significant challenges and risks expanding into new technologies (or expanding our geographical or customer base for those new technologies), including:

- our ability to compete with the large number of other companies pursuing similar business opportunities in energy storage and solar PV power generation, many of which already have established businesses in these areas and/or have greater financial, strategic, technological or other resources than we have;

our ability to obtain financing on terms we consider acceptable, or at all, which we may need, for example, to obtain any technology, personnel, intellectual property, or to acquire one or more existing businesses as a platform for our expansion, or to fund internal research and development, for energy storage and solar PV electric power generation products and services;

our ability to provide energy storage or solar electric power generation products or services that keep pace with rapidly changing technology, customer preferences, equipment costs, market conditions and other factors that will impact these markets;

our ability to devote the amount of management time and other resources required to implement this plan, consistent with continuing to grow our core geothermal and recovered energy businesses; and

our ability to recruit appropriate employees.

Expanding our geothermal and recovered energy businesses to new customers and geographical areas will have many of the same risks and uncertainties as those outlined above. These or other factors could mean that we decide to change or even abandon, or are otherwise unable to implement, one or more elements of the plan.

Implementing the plan may involve various costs, including, among other things:

opportunity costs associated with foregone alternative uses of our resources;

various expense items that will impact our current financial results; and

asset revaluations (for example, businesses or other assets acquired for new energy storage or solar PV power generation products or services may suffer impairment charges, as a result of rapidly changing technology, market conditions or otherwise).

These costs may not be recovered, in whole or in part, if one or more elements of the plan are not successfully implemented. These costs, or the failure to implement successfully one or more elements of the plan, could adversely affect our reputation and the reputation of our subsidiaries and could materially and adversely affect our business, financial condition, future results and cash flow and the price at which our common stock is traded.

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Apart from the risks associated with implementing the plan, the plan itself will expose us to other risks and uncertainties once implemented. For example, expanding our customer base may expose us to different credit profile customers than our current customers. As another example, expanding our geographic base will subject us to risks associated with doing business in new foreign countries in which we will have to learn the business and political environment, and expanding into new technologies will expose us to risks associated with those products and services. Some of these risks may be similar to those we now face, as described in other risks factors; others may differ or be unknown to us now. The success of the plan, once implemented, will depend, among other things, on our ability to manage these risks effectively.

The trading price of our common stock could decline if securities, industry analysts or our investors disagree with our strategic plan or the way we implement it, either as a result of the factors outlined above or for other reasons.

Accordingly, there is no assurance that the plan will enhance shareholder value through long-term growth of the Company to the extent currently anticipated by our management or at all.

We may not be able to successfully integrate companies, which we acquired and may acquire in the future, which could materially and adversely affect our business, financial condition, future results and cash flow.

Our strategy is to continue to expand in the future, including through acquisitions. Integrating acquisitions is often costly, and we may not be able to successfully integrate our acquired companies with our existing operations without substantial costs, delays or other adverse operational or financial consequences. Integrating our acquired companies involves a number of risks that could materially and adversely affect our business, including:

- failure of the acquired companies to achieve the results we expect;

- inability to retain key personnel of the acquired companies;

- risks associated with unanticipated events or liabilities; and

- the difficulty of establishing and maintaining uniform standards, controls, procedures and policies, including accounting controls and procedures.

If any of our acquired companies suffers customer dissatisfaction or performance problems, this could adversely affect the reputation of our group of companies and could materially and adversely affect our business, financial condition, future results and cash flow.

The power generation industry is characterized by intense competition, and we encounter competition from electric utilities, other power producers, and power marketers that could materially and adversely affect our business, financial condition, future results and cash flow.

The power generation industry is characterized by intense competition from electric utilities, other power producers and power marketers. In recent years, there has been increasing competition in the sale of electricity, in part due to excess capacity in a number of U.S. markets and an emphasis on short-term or “spot” markets, and competition has contributed to a reduction in electricity prices. For the most part, we expect that power purchasers interested in long-term arrangements will engage in “competitive bid” solicitations to satisfy new capacity demands. This competition could adversely affect our ability to obtain PPAs and the price paid for electricity by the relevant power purchasers. There is also increasing competition between electric utilities. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the future will put further pressure on power purchasers to reduce the prices at which they purchase electricity from us.

We face increasing competition from other companies engaged in the solar, energy storage, demand response and energy management sectors.

The solar power market is intensely competitive and rapidly evolving. We compete with many companies that have longer operating histories in this sector, larger customer bases, and greater brand recognition, as well as, in some cases, significantly greater financial and marketing resources than us. In some cases, these competitors are vertically integrated in the solar energy sector, manufacturing Solar PV, silicon wafers, and other related products for the solar industry, which may give them an advantage in developing, constructing, owning and operating solar power projects. Our limited experience in the Solar PV sector may affect our ability to successfully develop, construct, finance, and operate Solar PV power projects.

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While our Viridity business does not currently experience intense competition in the younger, less mature energy storage, demand response and energy management markets, this is expected to change in light of recent rapid growth observed in these markets. We expect that our competitors in the energy storage, demand response and energy management markets will include utilities, independent entities, new start-ups, and third party investors, who may compete more successfully in these markets than our Viridity business. If we are unable, as a result of increased competition, to expand our customer base or increase our market share in these rapidly growing markets, our business, financial condition, future results and cash flow could be materially and adversely affected.

The existence of a prolonged force majeure event or a forced outage affecting a power plant or the transmission system of the IID could reduce our net income and materially and adversely affect our business, financial condition, future results and cash flow.

The operation of our subsidiaries' geothermal power plants is subject to a variety of risks discussed elsewhere in these risk factors, including events such as fires, explosions, earthquakes, landslides, floods, severe storms, volcanic eruptions, lava flow or other similar events. If a power plant experiences an occurrence resulting in a force majeure event, although our subsidiary that owns that power plant would be excused from its obligations under the relevant PPA, the relevant power purchaser may not be required to make any capacity and/or energy payments with respect to the affected power plant for as long as the force majeure event continues and, pursuant to certain of our PPAs, will have the right to prematurely terminate the PPA. Additionally, to the extent that a forced outage has occurred, the relevant power purchaser may not be required to make any capacity and/or energy payments to the affected power plant, and if as a result the power plant fails to attain certain performance requirements under certain of our PPAs, the power purchaser may have the right to permanently reduce the contract capacity (and correspondingly, the amount of capacity payments due pursuant to such agreements in the future), seek refunds of certain past capacity payments, and/or prematurely terminate the PPA. As a consequence, we may not receive any net revenues from the affected power plant other than the proceeds from any business interruption insurance that applies to the force majeure event or forced outage after the relevant waiting period, and may incur significant liabilities in respect of past amounts required to be refunded.

In addition, if the transmission system of the IID experiences a force majeure event or a forced outage which prevents it from transmitting the electricity from the Heber complex, the Ormesa complex or the North Brawley power plant to the relevant power purchaser, the relevant power purchaser would not be required to make energy payments for such non-delivered electricity and may not be required to make any capacity payments with respect to the affected power plant for as long as such force majeure event or forced outage continues. The impact of such force majeure would depend on the duration thereof, with longer outages resulting in greater loss of revenues. In the event of any such force majeure event, our business, financial condition, future results and cash flows could be materially and adversely affected.

Some of our leases will terminate if we do not extract geothermal resources in "commercial quantities", thus requiring us to enter into new leases or secure rights to alternate geothermal resources, none of which may be available on terms as favorable to us as any such terminated lease, if at all.

Most of our geothermal resource leases are for a fixed primary term, and then continue for so long as geothermal resources are extracted in “commercial quantities” or pursuant to other terms of extension. The land covered by some of our leases is undeveloped and has not yet produced geothermal resources in commercial quantities. Leases that cover land which remains undeveloped and does not produce, or does not continue to produce, geothermal resources in commercial quantities and leases that we allow to expire, will terminate. In the event that a lease is terminated and we determine that we will need that lease once the applicable power plant is operating, we would need to enter into one or more new leases with the owner(s) of the premises that are the subject of the terminated lease(s) in order to develop geothermal resources from, or inject geothermal resources into, such premises or secure rights to alternate geothermal resources or lands suitable for injection. We may not be able to do this or may not be able to do so without incurring increased costs, which could materially and adversely affect our business, financial condition, future results and cash flow.

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Our BLM leases may be terminated if we fail to comply with any of the provisions of the Geothermal Steam Act or if we fail to comply with the terms or stipulations of such leases, which could materially and adversely affect our business, financial condition, future results and cash flow.

Pursuant to the terms of our BLM leases, we are required to conduct our operations on BLM-leased land in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the relevant land. Additionally, certain BLM leases contain additional requirements, some of which relate to the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plants or animals. In the event of a default under any BLM lease, or the failure to comply with such requirements, or any non-compliance with any of the provisions of the Geothermal Steam Act or regulations issued thereunder, the BLM may, 30 days after notice of default is provided to our relevant project subsidiary, suspend our operations until the requested action is taken or terminate the lease, either of which could materially and adversely affect our business, financial condition, future results and cash flow.

Some of our leases (or subleases) could terminate if the lessor (or sublessor) under any such lease (or sublease) defaults on any debt secured by the relevant property, thus terminating our rights to access the underlying geothermal resources at that location.

The fee interest in the land which is the subject of some of our leases (or subleases) may currently be or may become subject to encumbrances securing loans from third-party lenders to the lessor (or sublessor). Our rights as lessee (or sublessee) under such leases (or subleases) are or may be subject and subordinate to the rights of any such lender. Accordingly, a default by the lessor (or sublessor) under any such loan could result in a foreclosure on the underlying fee interest in the property and thereby terminate our leasehold interest and result in the shutdown of the power plant located on the relevant property and/or terminate our right of access to the underlying geothermal resources required for our operations.

In addition, a default by a sublessor under its lease with the owner of the property that is the subject of our sublease could result in the termination of such lease and thereby terminate our sublease interest and our right to access the underlying geothermal resources required for our operations.

Current and future urbanizing activities and related residential, commercial, and industrial developments may encroach on or limit geothermal or Solar PV activities in the areas of our power plants, thereby affecting our ability to utilize access, inject and/or transport geothermal resources on or underneath the affected surface areas.

Current and future urbanizing activities and related residential, commercial and industrial development may encroach on or limit geothermal activities in the areas of our power plants or construction and operation of Solar PV facilities, thereby affecting our ability to utilize, access, inject, and/or transport geothermal resources on or underneath the affected surface areas or build Solar PV facilities, which require large areas of relatively flat land. In particular, the Heber power plants rely on an area, which we refer to as the Heber Known Geothermal Resource Area, or Heber KGRA, for the geothermal resource necessary to generate electricity at the Heber power plants. Imperial County has adopted a “specific plan area” that covers the Heber KGRA, which we refer to as the “Heber Specific Plan Area”. The Heber Specific Plan Area allows commercial, residential, industrial and other employment oriented development in a mixed-use orientation, which currently includes geothermal uses. Several of the landowners from whom we hold geothermal leases have expressed an interest in developing their land for residential, commercial, industrial or other surface uses in accordance with the parameters of the Heber Specific Plan Area. Currently, Imperial County’s Heber Specific Plan Area is coordinated with the cities of El Centro and Calexico. There has been ongoing underlying interest since the early 1990s to incorporate the community of Heber. While any incorporation process would likely take several years, if Heber were to be incorporated, the City of Heber could replace Imperial County as the governing land use authority, which, depending on its policies, could have a significant effect on land use and availability of geothermal resources.

Current and future development proposals within Imperial County and the City of Calexico, applications for annexations to the City of Calexico, and plans to expand public infrastructure may affect surface areas within the Heber KGRA, thereby limiting our ability to utilize, access, inject and/or transport the geothermal resource on or underneath the affected surface area that is necessary for the operation of our Heber power plants, which could adversely affect our operations and reduce our revenues.

Current construction works and urban developments in the vicinity of our Steamboat complex of power plants in Nevada may also affect future permitting for geothermal operations relating to those power plants. Such works and developments include plans for the construction of a new casino hotel and other commercial or industrial developments on land in the vicinity of our Steamboat complex.

We depend on key personnel for the success of our business.

In general, our success depends to a significant extent on the performance of our senior management, particularly the continued service of our key employees. Our success also depends on our ability to identify, hire and retain other qualified and experienced key personnel. Although to date we have been successful in identifying, hiring and retaining the services of senior management, we face risks associated with our ability to locate or employ on acceptable terms qualified replacements for our senior management or key employees if their services were no longer available, and with the inherent difficulties and uncertainties of transitioning the Company under the leadership of new management.

In the demand response industry, there is a relatively small pool of experienced personnel. In the relatively new energy storage market, there is an even smaller pool of experienced personnel. Our plans to grow the Viridity business are dependent on our ability to attract and retain highly specialized demand response and energy storage personnel.

Our inability to successfully identify, hire and retain any key employee could materially and adversely affect our business, financial condition, future results and cash flow.

Our power plants have generally been financed through a combination of our corporate funds and limited or non-recourse project finance debt and lease financing. If our project subsidiaries default on their obligations under such limited or non-recourse debt or lease financing, we may be required to make certain payments to the relevant debt holders, and if the collateral supporting such leveraged financing structures is foreclosed upon we may lose certain of our power plants.

Our power plants have generally been financed using a combination of our corporate funds and limited or non-recourse project finance debt or lease financing. Limited recourse project finance debt refers to our additional agreement, as part of the financing of a power plant, to provide limited financial support for the power plant subsidiary in the form of limited guarantees, indemnities, capital contributions and agreements to pay certain debt service deficiencies. Non-recourse project finance debt or lease financing refers to financing arrangements that are repaid solely from the power plant's revenues and are secured by the power plant's physical assets, major contracts, cash accounts and, in many cases, our ownership interest in the project subsidiary. If our project subsidiaries default on their obligations under the relevant debt documents, creditors of a limited recourse project financing will have direct recourse to us, to the extent of our limited recourse obligations, which may require us to use distributions received by us from other power plants, as well as other sources of cash available to us, in order to satisfy such obligations. In addition, if our project subsidiaries default on their obligations under the relevant debt documents (or a default under such debt documents arises as a result of a cross-default to the debt documents of some of our other power plants) and the creditors foreclose on the relevant collateral, we may lose our ownership interest in the relevant project subsidiary or our project subsidiary owning the power plant would only retain an interest in the physical assets, if any, remaining after all debts and obligations were paid in full.

Changes in costs and technology may significantly impact our business by making our power plants and products less competitive.

A basic premise of our business model is that generating baseload power at geothermal power plants produces electricity at a competitive price. However, traditional coal-fired systems and gas-fired systems may under certain economic conditions produce electricity at lower average prices than our geothermal plants. In addition, there are other technologies that can produce electricity such as hydroelectric systems, fuel cells, microturbines, wind turbines, energy storage systems and solar PV systems. Some of these alternative technologies currently produce electricity at a higher average price than our geothermal plants while others produce electricity at a lower average price, It is possible that technological advances and economies of scale will further reduce the cost of alternate methods of power generation. It is also possible that energy technologies will compete with our basic premise of a firm (non-intermittent) renewable baseload power source by combining renewable technologies with energy storage to provide an alternative to firm baseload energy. If this were to happen, the competitive advantage of our power plants may be significantly impaired.

Our expectations regarding the market potential for the development of recovered energy-based power generation may not materialize, and as a result we may not derive any significant revenues from this line of business.

Demand for our recovered energy-based power generation units may not materialize or grow at the levels that we expect. We currently face competition in this market from manufacturers of conventional steam turbines and may face competition from other related technologies in the future. If this market does not materialize at the levels that we expect, we will not generate any material revenues.

Our intellectual property rights may not be adequate to protect our business.

Our existing intellectual property rights, including those we acquired in connection with the acquisition of our Viridity business, may not be adequate to protect our business. While we occasionally file patent applications, patents may not be issued on the basis of such applications or, if patents are issued, they may not be sufficiently broad to protect our technology. In addition, any patents issued to us or for which we have use rights may be challenged, invalidated or circumvented.

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In order to safeguard our unpatented proprietary know-how, trade secrets and technology, we rely primarily upon trade secret protection and non-disclosure provisions in agreements with employees and others having access to confidential information. These measures may not adequately protect us from disclosure or misappropriation of our proprietary information.

Even if we adequately protect our intellectual property rights, litigation may be necessary to enforce these rights, which could result in substantial costs to us and a substantial diversion of management attention. Also, while we have attempted to ensure that our technology and the operation of our business do not infringe other parties' patents and proprietary rights, our competitors or other parties may assert that certain aspects of our business or technology may be covered by patents held by them. Infringement or other intellectual property claims, regardless of merit or ultimate outcome, can be expensive and time-consuming and can divert management's attention from our core business.

Threats of terrorism and catastrophic events that could result from terrorism, cyber-attacks, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may impact our operations in unpredictable ways and could adversely affect our business, financial condition, future results and cash flow.

We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber-attacks, including, among others, malware, viruses and attachments to e-mails, and other disruptive activities of individuals or groups. Our generation and transmission facilities, information technology systems and other infrastructure facilities, systems and physical assets, including our Viridity business's VPower™ software platform, could be directly or indirectly affected by such activities. Terrorist acts or other similar events could harm our business by limiting our ability to generate or transmit power and by delaying the development and construction of new generating facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure our assets, and could adversely affect operations by contributing to the disruption of supplies and markets for geothermal and recovered energy. Such events could also impair our ability to raise capital by contributing to financial instability and lower economic activity.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our implementation of security measures, all of our technology systems (and any programs or data stored thereon or therein) are vulnerable to security breaches, failures, data leakage or unauthorized access due to such activities. Those breaches and events may result from acts of our employees, contractors or third parties. If our technology systems were to fail or be breached and we were unable to recover in a timely way, we would be unable to fulfill critical business functions, and sensitive confidential and other data could be compromised, which could adversely affect our business, financial condition, future results and cash flow.

The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs. These types of events could adversely affect our business, financial condition, future results and cash flow. In addition such events could require significant management attention and resources and could adversely affect our reputation among customers and the public.

A disruption of transmission or the transmission infrastructure facilities of third parties could negatively impact our business. Because generation and transmission systems are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system within our systems or within a neighboring system. Any such disruption could adversely affect our business, financial condition, future results and cash flow.

Possible fluctuations in the cost of construction, raw materials, commodities and drilling may materially and adversely affect our business, financial condition, future results, and cash flow.

Our manufacturing operations are dependent on the supply of various raw materials, including primarily steel and aluminum, commodities and industrial equipment components that we use. We currently obtain all such raw materials, commodities and equipment at prevailing market prices. We are not dependent on any one supplier and do not have any long-term agreements with any of our suppliers. Future cost increases of such raw materials, commodities and equipment, to the extent not otherwise passed along to our customers, could adversely affect our profit margins.

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Conditions in and around Israel, where the majority of our senior management and our main production and manufacturing facilities are located, may adversely affect our operations and may limit our ability to produce and sell our products or manage our power plants.

The majority of our senior management and our main production and manufacturing facilities are located in Israel. As such, political, economic and security conditions in Israel directly affect our operations.

Since the establishment of the State of Israel in 1948, a number of armed conflicts have taken place between Israel and its Arab neighbors, and the continued state of hostility, varying in degree and intensity, has led to security and economic problems for Israel.

Negotiations between Israel and representatives of the Palestinian Authority in an effort to resolve the state of conflict have been sporadic and have failed to result in peace. The establishment in 2006 of a government in the Gaza territory by representatives of the Hamas militant group has created additional unrest and uncertainty in the region. In each of December 2008, November 2012 and July 2014, Israel engaged in an armed conflict with Hamas, each of which involved additional missile strikes from the Gaza Strip into Israel and disrupted most day-to-day civilian activity in the proximity of the border with the Gaza Strip. Our production facilities in Israel are located approximately 26 miles from the border with the Gaza Strip.

The political instability and civil unrest in the Middle East and North Africa (including the ongoing civil war in Syria) as well as the increased tension between Iran and Israel have raised new concerns regarding security in the region and the potential for armed conflict or other hostilities involving Israel. We could be adversely affected by any such hostilities, the interruption or curtailment of trade between Israel and its trading partners, or a significant downturn in the economic or financial condition of Israel. In addition, the sale of products manufactured in Israel may be adversely affected in certain countries by restrictive laws, policies or practices directed toward Israel or companies having operations in Israel.

In addition, some of our employees in Israel are subject to being called upon to perform military service in Israel, and their absence may have an adverse effect upon our operations. Generally, unless exempt, male adult citizens of Israel under the age of 41 are obligated to perform up to 36 days of military reserve duty annually. Additionally, all such citizens are subject to being called to active duty at any time under emergency circumstances.

These events and conditions could disrupt our operations in Israel, which could materially and adversely affect our business, financial condition, future results, and cash flow.

We are a holding company and our revenues depend substantially on the performance of our subsidiaries and the power plants they operate, most of which are subject to restrictions and taxation on dividends and distributions.

We are a holding company whose primary assets are our ownership of the equity interests in our subsidiaries. We conduct no other business and, as a result, we depend entirely upon our subsidiaries' earnings and cash flow.

The agreements pursuant to which most of our subsidiaries have incurred debt restrict the ability of these subsidiaries to pay dividends, make distributions or otherwise transfer funds to us prior to the satisfaction of other obligations, including the payment of operating expenses, debt service and replenishment or maintenance of cash reserves. In the case of some of our power plants that are owned jointly with other partners, there may be certain additional restrictions on dividend distributions pursuant to our agreements with those partners. In all of the foreign countries where our existing power plants are located, dividend payments to us are also subject to withholding taxes. Each of the events described above may reduce or eliminate the aggregate amount of revenues we can receive from our subsidiaries.

We have identified a material weakness in our internal control over financial reporting which, if not timely remediated, may adversely affect the accuracy and reliability of our financial statements, and our reputation, business and the price of our common stock, as well as lead to a loss of investor confidence in us.

In connection with the change in our repatriation strategy and the related release of the US income tax valuation allowance in the second quarter of 2017, we did not perform an effective risk assessment related to our internal controls over the accounting for income taxes. As a result, we identified a deficiency in the design of our internal control over financial reporting related to our accounting for income taxes, which affected the recording of income tax accounts by us in our interim and annual consolidated financial statements during 2017, including audit adjustments to the income tax accounts. As described under "Item 9A. Controls and Procedures" below, our management has concluded that this deficiency constitutes a material weakness in our internal control over financial reporting and, accordingly, internal control over financial reporting and our disclosure controls and procedures were not effective as of December 31, 2017.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

While we have developed and are in the process of implementing a remediation plan to remediate this material weakness, there can be no assurance that this will occur in 2018. We may identify additional material weaknesses in our internal control over financial reporting in the future. If we are unable to remediate this material weakness or we identify additional material weaknesses in our internal control over financial reporting in the future, our ability to analyze, record and report financial information accurately, to prepare our financial statements within the time periods specified by the rules and forms of the SEC and to otherwise comply with our reporting obligations under the federal securities laws and our long-term debt and credit agreements will likely be adversely affected. The occurrence of, or failure to remediate, this material weakness and any future material weaknesses in our internal control over financial reporting may adversely affect the accuracy and reliability of our financial statements, and our reputation, business and the price of our Common Stock or any other securities we may issue, as well as lead to a loss of investor confidence in us.

U.S. federal income tax reform could adversely affect us.

On December 22, 2017, U.S. federal tax legislation, commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) was signed into law, significantly reforming the U.S. Internal Revenue Code. The Tax Act, among other things, includes changes to U.S. federal tax rates (including reduction of the corporate tax rate from 35% to 21%), imposes significant additional limitations on the deductibility of interest, allows for the expensing of capital expenditures, puts into effect the migration from a “worldwide” system of taxation to a territorial system and modifies or repeals many business deductions and credits.

The Tax Act is likely to make some borrowing more expensive. It denies interest deductions on debt starting in 2018 to the extent a company's net interest expense exceeds 30 percent of its adjusted taxable income. Its income for this purpose means income ignoring interest expense, interest income, net operating losses and -- only through 2021 -- depreciation, amortization and depletion. Thus, the 30-percent limit is more likely to come into play after 2021 when depreciation, amortization and depletion are no longer added back to the 30-percent base. Any interest that cannot be deducted in a year can be carried forward indefinitely.

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The Tax Act subjects U.S. corporations with offshore subsidiaries to a one-time U.S. tax on untaxed earnings in offshore holding companies as if the earnings had been brought back to the U.S. thereby triggering a tax. All post-1986 net "earnings and profits" in offshore holding companies will be taxed at a 15.5 percent rate to the extent they are being held in cash or cash equivalents and at an eight percent rate otherwise. Companies must calculate the earnings as of November 2, 2017 and December 31, 2017 and pay U.S. tax on whichever amount is higher. The tax can be paid ratably over eight years. Eight percent of the tax would have to be paid in each of the first five years starting in 2017, increasing to 15 percent in year six, 20 percent in year seven and 25 percent in year eight.

Corporations will no longer be able to use net operating losses incurred after 2017 to reduce income by more than 80 percent in a year, and corporations will no longer be able to carry such losses back two years as they have been allowed to do in the past.

Starting in 2018, the U.S. will no longer allow some cross-border interest and royalty payments to related companies to be deducted. This would happen if the other country treats the payments as something other than interest or royalties for its tax purposes or the two countries treat the U.S. company making the payments differently: for example, one treats it as a corporation and the other treats it as fiscally transparent or vice versa. Once the provision is triggered, deductions would be denied in the U.S. to the extent the payment does not have to be reported as income in the foreign country.

We continue to examine the impact the Tax Act may have on our business. Notwithstanding the reduction in the corporate income tax rate, the overall impact of the Tax Act is uncertain, and our business, financial condition, future results and cash flow, as well as our stock price, could be adversely affected.

Possible application of the new base erosion anti-avoidance tax in the U.S. may adversely affect us.

The recently enacted Tax Act in the U.S. included a base erosion and anti-abuse tax, or BEAT, that could apply to us and, more importantly, could reduce the amount of tax equity that can be raised on geothermal projects on which PTCs will be claimed. The aim of the base erosion tax is to prevent multinational companies from reducing their U.S. taxes by “stripping” earnings across the U.S. border by making payments to foreign affiliates that can be deducted in the U.S. An example of such a payment is interest on an intercompany loan or a payment to a back office in a foreign country for equipment or services. The goal of the base erosion tax is to ensure that multinational companies do not use cross-border payments to reduce their U.S. taxes to less than 10 percent of an expanded definition of taxable income. The base erosion tax requires an annual calculation. The tax only applies to companies with at least $500 million in average annual gross receipts in the three prior years before the calculation. If the tax applies to us, our tax equity raised on geothermal projects on which PTCs can be claimed may be reduced, which in turn may materially and adversely affect our business, financial condition, future results and cash flow.

The Israeli Tax Ruling we obtained in connection with our acquisition of Ormat Industries imposes conditions that may limit our flexibility in operating our business and our ability to enter into certain corporate transactions.

The Israel Tax Ruling we obtained in connection with the acquisition of Ormat Industries imposes a number of conditions that limit our flexibility in operating our business and in engaging in certain corporate transactions. Until the end of 2018, we agreed to maintain (and, to the extent that our operations expand, likewise expand) the production activities we currently carry out in Israel. Under certain circumstances, these conditions may not allow us the flexibility that we need to operate our business and may prevent us from taking advantage of strategic opportunities that would benefit our business and our stockholders.

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A substantial percentage of our common stock is held by stockholders whose interests may conflict with the interests of our other stockholders.

On July 26, 2017, ORIX Corporation ("ORIX") purchased approximately 22% of our shares of common stock outstanding. Pursuant to the Governance Agreement between the Company and ORIX entered into in connection with this stock purchase transaction, ORIX has the right to designate three directors to our Board for as long as ORIX and its affiliates collectively hold at least 18% of the voting power of all of the outstanding voting securities of the Company as well as the right to representation on certain committees of our Board. ORIX may also exercise certain registration rights pursuant to the Registration Rights Agreement between the Company and ORIX.

As a result of these rights and ORIX's beneficial ownership of our common stock, ORIX could exert influence through its Board representation on the business, operations and management of the Company and its subsidiaries, including our strategic plans, or, as a significant stockholder, on matters submitted to a vote of our stockholders, including mergers, consolidations and the sale of all or substantially all of our assets. This concentration of ownership of our common stock could delay or prevent proxy contests, mergers, tender offers, or other purchases of our common stock that might otherwise give our stockholders the opportunity to realize a premium over the then-prevailing market price for our shares. If ORIX exercises its registration rights to require the Company to register for sale the common stock held by ORIX or ORIX otherwise sells its common stock in the public markets, the price of our common stock may decline. This concentration of ownership may also adversely affect the liquidity of our common stock.

The price of our common stock may fluctuate substantially, and your investment may decline in value.

The market price of our common stock may be highly volatile and may fluctuate substantially due to many factors, including:

- actual or anticipated fluctuations in our results of operations including as a result of seasonal variations in our Electricity segment-based revenues or variations from year-to-year in our Product segment-based revenues;
- variance in our financial performance from the expectations of market analysts;
- conditions and trends in the end markets we serve, and changes in the estimation of the size and growth rate of these markets;
- our ability to integrate acquisitions;
- announcements of significant contracts by us or our competitors;
- changes in our pricing policies or the pricing policies of our competitors;
- restatements of historical financial results and changes in financial forecasts;
- loss of one or more of our significant customers;
- legislation;
- changes in market valuation or earnings of our competitors;
- the trading volume of our common stock;

the trading of our common stock on multiple trading markets, which takes place in different currencies and at different times; and

general economic conditions.

In addition, the stock market in general, and the NYSE and the market for energy companies in particular, have experienced extreme price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of particular companies affected. These broad market and industry factors may materially harm the market price of our common stock, regardless of our operating performance. In the past, following periods of volatility in the market price of a company’s securities, securities class-action litigation has often been instituted against that company. Such litigation, if instituted against us, could result in substantial costs and a diversion of management’s attention and resources, which could materially harm our business, financial condition, future results and cash flow.

Regulations related to conflict minerals may force us to incur additional expenses and may damage our relationship with certain customers.

On August 22, 2012, the SEC adopted requirements regarding mandatory disclosure for companies regarding their use of "conflict minerals" (including tantalum, tin, tungsten and gold) in their products. In general, while we do not directly purchase or use any of these “conflict minerals” as raw materials in the products we manufacture or as part of our manufacturing processes, we will need to examine whether such minerals are contained in the products supplied to us by third parties and, if so, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. If we utilize any of these minerals and they are necessary to the production or functionality of any of our products or products we are contracted to manufacture, we will need to conduct specified due diligence activities and file with the SEC a report disclosing, among other things, whether such minerals originate from the Democratic Republic of Congo or adjoining countries. The implementation of these SEC rules could adversely affect the sourcing, availability and pricing of minerals used in the manufacture of certain components incorporated in our products. In addition, we expect to incur additional costs to comply with the disclosure requirements, including costs related to determining the source of any of the relevant minerals and metals used in our products, and possibly additional expenses related to any changes to our products we may decide are advisable based upon our due diligence findings. Since our supply chain is complex, we may not be able to sufficiently verify the origins for these minerals and metals used in our products through the diligence procedures that we implement, which may harm our reputation. In such event, we may also face difficulties in satisfying customers who require that all of the components of our products are certified as conflict mineral free.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We currently lease corporate offices at 6225 Neil Road, Reno, Nevada 89511-1136. We also occupy an approximately 807,000 square foot office and manufacturing facility located in the Industrial Park of Yavne, Israel, which we lease from the Israel Land Administration. See Item 13 — "Certain Relationships and Related Transactions". We also lease small offices in each of the countries in which we operate.

We are planning to move from our current corporate offices to larger offices during the second quarter of 2018. We believe that our current manufacturing facilities will be adequate for our operations as currently conducted.

Each of our power plants is located on property leased or owned by us or one of our subsidiaries, or is a property that is subject to a concession agreement.

Information and descriptions of our plants and properties are included in Item 1 — "Business", of this annual report.

ITEM 3. LEGAL PROCEEDINGS

There were no material developments in any legal proceedings to which the Company was a party during fiscal year 2017, other than as described below.

Jon Olson and Hilary Wilt, together with Puna Pono Alliance, filed a complaint on February 17, 2015 in the Third Circuit Court for the State of Hawaii, requesting declaratory and injunctive relief requiring that Puna Geothermal Venture comply with an ordinance that the plaintiffs allege will prohibit PGV from engaging in night drilling operations at its KS-16 well site. On May 17, 2015, the original complaint was amended to add the County of Hawaii and the State of Hawaii Department of Land and Natural Resources as defendants to the case. On October 10, 2016, the court issued its decision in response to each of the plaintiffs' and defendants' motions for summary judgment, denying plaintiffs' motion and granting defendant PGV's and the County of Hawaii's cross motions for summary judgment, effectively rendering the plaintiffs' action moot. On January 23, 2017, the plaintiffs filed a motion requesting that the Intermediate Court of Appeals address appellate jurisdiction, which was denied by the court on April 20, 2017 as premature. We believe that we have valid defenses under law, and intend to defend this action vigorously.

On July 8, 2014, Global Community Monitor, LiUNA, and two residents of Bishop, California filed a complaint in the U.S. District Court for the Eastern District of California, alleging that Mammoth Pacific, L.P., the Company and Ormat Nevada are operating three geothermal generating plants in Mammoth Lakes, California (MP-1, MP-II and PLES-I) in violation of the federal Clean Air Act and Great Basin Unified Air Pollution Control District rules. On June 26, 2015, in response to a motion by the defendants, the court dismissed all but one of the plaintiffs' causes of action. On January 6, 2017, the court issued its order regarding several pending motions, including plaintiffs' motion for partial summary judgment, defendants' motion for summary judgment, defendants' motion to exclude and defendants' motion for leave to file a sur-reply. The impact of the court's January 6, 2017 order is to deny the plaintiffs' sole remaining cause of action. No appeal by the plaintiffs is expected and we consider this case to be effectively closed.

On March 29, 2016, a former local sales representative in Chile, Aquavant, S.A., filed a claim against our subsidiaries in the 27th Civil Court of Santiago, Chile on the basis of unjust enrichment. The claim requests that the court order us to pay Aquavant \$4.8 million in connection with its activities in Chile, including the EPC contract for the Cerro Pabellon project and various geothermal concessions, plus 3.75% of our geothermal products sales in Chile over the next 10 years. Pursuant to various motions submitted by the defendants and the plaintiffs to various courts, including the Court of Appeals, the case was removed from the original court and then refiled before the 11th Civil Court of Santiago. In February 2018, our preliminary defenses were denied by the lower court, and are currently pending on appeal. We timely filed our answer to the claim on the merits, and the plaintiff filed its response (replication). We believe that we have valid defenses under law, and intend to defend this action vigorously.

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On August 5, 2016, George Douvris, Stephanie Douvris, Michael Hale, Cheryl Cacocci, Hillary E. Wilt and Christina Bryan, acting for themselves and on behalf of all other similarly situated residents of the lower Puna District, filed a complaint in the Third Circuit Court for the State of Hawaii seeking certification of a class action for preliminary and permanent injunctive relief, consequential and punitive damages, attorney’s fees and statutory interest against PGV and other presently unknown defendants. On December 12, 2016, the federal district court granted plaintiffs’ motion for joinder of HELCO as a co-defendant, and the case, which had previously been removed to the U.S. District Court for the District of Hawaii, was remanded back to the Third Circuit Court. The amended complaint alleged that injuries and other damages in an undisclosed amount were caused to the plaintiffs as a result of an alleged toxic release by PGV in the wake of Hurricane Iselle in August 2014. On June 14, 2017, the Third Circuit Court denied HELCO’s motion to dismiss the complaint against HELCO. Discovery is underway. We believe that we have valid defenses under law, and intend to defend this action vigorously.

On June 20, 2016, Nadia Garcia, individually and as successor in interest to Thomas Garcia Valenzuela, and as guardian ad litem to Emerie Garcia, Khamilla Garcia and Reyene Adam, filed a complaint against the Company, Ormat Nevada and Ormesa LLC in the Superior Court of Imperial County seeking unspecified monetary damages. The complaint alleges that the Ormat defendants caused the wrongful death, personal injury and other harm to Thomas Garcia when he was employed by Martin Hydroblasting Services, Inc. and suffered injuries leading to his death while performing work at the Ormesa plant site on or around March 31, 2016. The plaintiffs and the deceased's employer’s insurer reached an out of court settlement on May 25, 2017 that was approved by the US District Court for the Southern District of California. The case has been dismissed, without liability to us.

On February 18, 2018, Western Watersheds Project ("WWP") filed a notice of appeal and petition for standing with respect to the January 16, 2018 BLM decision approving Addendum 2 to Operation Plan & Utilization Plan for the McGinness Hills Geothermal Project. The appeal alleges that the January 2018 BLM decision authorizing construction and operation of Phase 3 of McGinness Hills causes harm to WWP and its members by allowing degradation of the wildlife habitat of the greater sage-grouse in that area. We have filed a motion to intervene as an interested party in support of the BLM.

In addition, from time to time, the Company is named as a party to various other lawsuits, claims and other legal and regulatory proceedings that arise in the ordinary course of our 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 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. ***MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES***

Our common stock has traded on the NYSE under the symbol "ORA" since November 11, 2004. Prior to November 11, 2004, there was no public market for our common stock. Effective on February 10, 2015, our common stock also began trading on the TASE.

As of March 1, 2018, there were 17 record holders of our common stock. On March 1, 2018, the closing price of our common stock as reported on the NYSE was $57.65 per share.

Dividends

We have adopted a dividend policy pursuant to which we currently expect to distribute at least 20% of our annual profits available for distribution by way of quarterly dividends. In determining whether there are profits available for distribution, our Board will take into account our business plan and current and expected obligations, and no distribution will be made that in the judgment of our Board would prevent us from meeting such business plan or obligations.

Notwithstanding this policy, dividends will be paid only when, as and if approved by our Board out of funds legally available therefor. The actual amount and timing of dividend payments will depend upon our financial condition, results of operations, business prospects and such other matters as the Board may deem relevant from time to time. Even if profits are available for the payment of dividends, the Board could determine that such profits should be retained for an extended period of time, used for working capital purposes, expansion or acquisition of businesses or any other appropriate purpose. As a holding company, we are dependent upon the earnings and cash flow of our subsidiaries in order to fund any dividend distributions and, as a result, we may not be able to pay dividends in accordance with our policy. Our Board may, from time to time, examine our dividend policy and may, in its absolute discretion, change such policy. In addition to the required Board approval for the payment of dividends, we can declare as dividends no more than 35% of annual net income as dividends due to restrictions related to its third-party debt (see Note 11 to our consolidated financial statements set forth in Item 8 of this annual report).

We have declared the following dividends over the past two years:

Date Declared	Dividend Amount per Share	Record Date	Payment Date
February 23, 2016	$ 0.31	March 15, 2016	March 29, 2016
May 4, 2016	$ 0.07	May 18, 2016	May 24, 2016
August 2, 2016	$ 0.07	August 16, 2016	August 30, 2016
November 7, 2016	$ 0.07	November 21, 2016	December 6, 2016
February 28, 2017	$ 0.17	March 15, 2017	March 29, 2017
May 8, 2017	$ 0.08	May 22, 2017	May 31, 2017
August 3, 2017	$ 0.08	August 15, 2017	August 29, 2017
November 7, 2017	$ 0.08	November 21, 2017	December 5, 2017
March 1, 2018	$ 0.23	March 14, 2018	March 29, 2018

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High/Low Stock Prices

The following table sets forth the high and low sales prices of our common stock for the years ended December 31, 2016 and 2017, and from January 1, 2018 until March 1, 2018:

	First Quarter 2016	**Second Quarter 2016**	**Third Quarter 2016**	**Fourth Quarter 2016**	**First Quarter 2017**	**Second Quarter 2017**	**Third Quarter 2017**	**Fourth Quarter 2017**	**January 1 to March 1, 2018**
High	$ 41.56	$ 44.45	$ 50.87	$ 53.71	$ 59.63	$ 61.49	$ 63.56	$ 66.46	$ 70.68
Low:	$ 33.29	$ 40.24	$ 43.19	$ 46.01	$ 51.44	$ 55.73	$ 55.06	$ 60.13	$ 57.51

Stock Performance Graph

The following performance graph represents the cumulative total shareholder return for the period November 11, 2004 (the date upon which trading of the Company's common stock commenced) through December 31, 2017 for our common stock, compared to the Standard and Poor's Composite 500 Index, and two peer groups.

Comparison of Cumulative Returns for the Period November 11, 2004 through December 31, 2017

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	For the Year Ended December 31,													
	2004	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Ormat Technologies Inc	9 %	74%	145%	267%	112%	152%	97 %	20 %	29 %	81 %	81 %	143%	258%	326%
Standard & Poor's Composite 500 Index	8 %	11%	26 %	31 %	-20 %	-1 %	12 %	12 %	27 %	65 %	84 %	82 %	100%	138%
NEX - renewable Index	9 %	30%	74 %	174%	7 %	50 %	28 %	-23 %	-28 %	12 %	11 %	7 %	-2 %	24 %
IPP Peers*	22%	26%	79 %	79 %	77 %	107%	119%	131%	165%	187%	222%	111%	89 %	138%
Renewable Peers*	41%	19%	63 %	204%	20 %	45 %	-25 %	-22 %	-30 %	-42 %	-23 %	17 %	-2 %	-16 %

* IPP Peers are The AES Corporation, NRG Energy Inc., Calpine Corporation and Covanta Holding Corp.

** Renewable Energy (Renewable) Peers are Acciona S.A. and U.S. Geothermal Inc.

The above Stock Performance Graph shall not be deemed to be soliciting material or to be filed with the SEC under the Securities Act and the Exchange Act except to the extent that the Company specifically requests that such information be treated as soliciting material or specifically incorporates it by reference into a filing under the Securities Act or the Exchange Act.

Equity Compensation Plan Information

For information on our equity compensation plan, refer to Item 12 — “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters”.

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ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth our selected consolidated financial data for the years ended and at the dates indicated. We have derived the selected consolidated financial data for the years ended December 31, 2017, 2016 and 2015 and as of December 31, 2017 and 2016 from our audited consolidated financial statements set forth in Item 8 of this annual report. Such consolidated financial data reflects the correction of certain prior period errors related to income taxes, as more fully described in Note 1 to our consolidated financial statements, which resulted in the restatement of our financial statements as of and for the year ended December 31, 2017 and the revision of our financial statements as of and for the year ended December 31, 2016 and the year ended December 31, 2015. We have derived the selected consolidated financial data for the years ended December 31, 2014 and 2013 and as of December 31, 2015, 2014 and 2013 from our audited consolidated financial statements not included herein. The consolidated financial data as of December 31, 2015 and as of and for the years ended December 31, 2014 and 2013 has also been adjusted to reflect the correction of certain prior period errors related to income taxes.

The information set forth below should be read in conjunction with Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements, including the notes thereto, set forth in Item 8 of this annual report.

	Year Ended December 31,				
	2017 (As restated)	**2016**	**2015**	**2014**	**2013**
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$468,329	$436,292	$375,920	$382,301	$329,747
Product	224,483	226,299	218,724	177,223	203,492
Total revenues	692,812	662,591	594,644	559,524	533,239
Cost of revenues:					
Electricity	272,266	261,573	242,612	246,630	232,874
Product	152,094	130,223	133,753	109,143	140,547
Total cost of revenues	424,360	391,796	376,365	355,773	373,421
Gross profit	268,452	270,795	218,279	203,751	159,818
Operating expenses:					
Research and development expenses	3,157	2,762	1,780	783	4,965
Selling and marketing expenses	15,600	16,424	16,077	15,425	24,613
General and administrative expenses	42,881	46,710	34,782	28,614	29,188
Write-off of unsuccessful exploration activities	1,796	3,017	1,579	15,439	4,094
Operating Income (loss)	205,018	201,882	164,061	143,490	96,958
Other income (expense):					
Interest income	988	971	297	312	1,332
Interest expense, net	(54,142)	(67,389)	(72,577)	(84,654)	(73,776)

Derivatives and foreign currency transaction gains (losses)	2,654	(5,534)	(1,622)	(5,839)	5,085
Income attributable to sale of tax benefits	17,878	16,503	25,431	24,143	19,945
Gain from sale of property, plant and equipment	—	—	—	7,628	—
Other non-operating expense, net	(1,666)	(5,345)	(1,991)	756	1,592
Income (loss) from continuing operations, before income taxes and equity in income (losses) of investees	170,730	141,088	113,599	85,836	51,136
Income tax (provision) benefit	(21,664)	(37,059)	16,057	(24,812)	(13,217)
Equity in earnings (losses) of investees, net	(1,957)	(7,735)	(5,508)	(3,213)	(250)
Income (loss) from continuing operations	147,109	96,294	124,148	57,811	37,669
Discontinued operations:					
Income from discontinued operations (including gain on disposal of $0, $0, $0, $0, and $3,646, respectively)	—	—	—	—	5,311
Income tax provision	—	—	—	—	(614)
Total income from discontinued operations	—	—	—	—	4,697
Net Income (loss)	147,109	96,294	124,148	57,811	42,366
Net income attributable to noncontrolling interest	(14,695)	(7,586)	(3,776)	(833)	(793)
Net income (loss) attributable to the Company's stockholders	$132,414	$88,708	$120,372	$56,978	$41,573

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	Year Ended December 31,				
	2017 (As restated)	2016	2015	2014	2013
	(Dollars in thousands, except per share data)				
Earnings (loss) per share attributable to the Company's stockholders:					
Basic:					
Income (loss) from continuing operations	$2.64	$1.79	$2.48	$1.25	$0.81
Discontinued operations:	—	—	—	—	0.10
Net Income (loss)	$2.64	$1.79	$2.48	$1.25	$0.91
Diluted:					
Income from continuing operations	$2.61	$1.77	$2.45	$1.24	$0.81
Discontinued operations	—	—	—	—	0.10
Net Income (loss)	$2.61	$1.77	$2.45	$1.24	$0.91
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:					
Basic	50,110	49,469	48,562	45,508	45,440
Diluted	50,769	50,140	49,187	45,859	45,475
Dividend per share declared	$0.41	$0.52	$0.26	$0.21	$0.08
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$47,818	230,214	185,919	40,230	57,354
Working capital	38,301	283,579	186,635	67,521	102,401
Property, plant and equipment, net (including construction-in process)	2,028,233	1,863,087	1,808,170	1,734,359	1,741,163
Total assets	2,623,864	2,461,569	2,273,982	2,101,525	2,138,674
Long-term debt (including current portion)	862,102	938,844	901,403	981,379	1,057,098
Equity	1,295,700	1,168,272	1,087,307	789,324	745,446

ITEM 7. *MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS*

You should read the following discussion and analysis of our results of operations, financial condition and liquidity in conjunction with our consolidated financial statements and the related notes. Some of the information contained in this discussion and analysis or set forth elsewhere in this annual report including information with respect to our plans and strategies for our business, statements regarding the industry outlook, our expectations regarding the future performance of our business, and the other non-historical statements contained herein are forward-looking statements. See "Cautionary Note Regarding Forward-Looking Statements." You should also review Item 1A — "Risk Factors" for a discussion of important factors that could cause actual results to differ materially from the results described herein or implied by such forward-looking statements.

RESTATEMENT AND REVISION OF THE CONSOLIDATED FINANCIAL STATEMENTS

As discussed in the Explanatory Note, this Amendment No. 1 to Form 10-K (this Amendment), amends and restates the Company's consolidated financial statements and related disclosures in Part II, Item 8. "Financial Statements and Supplementary Data" as of and for the year ended December 31, 2017 and revises the Company's consolidated financial statements as of and for the year ended December 31, 2016 and for the year ended December 31, 2015, to reflect the correction of certain errors discussed in Note 1 Restatement and Revision of the Consolidated Financial Statements. Accordingly, the Management's Discussion and Analysis of Financial Condition and Results of Operations set forth below reflects the effects of these restatements and revisions.

General

Overview of Fiscal Year 2017 Revenues

For the year ended December 31, 2017, our total revenues increased by 4.6% (from $662.6 million to $692.8 million) over the previous year.

For the year ended December 31, 2017, Electricity segment revenues were $468.3 million, compared to $436.3 million for the year ended December 31, 2016, an increase of 7.3%. Product segment revenues for the year ended December 31, 2017 were $224.5 million, compared to $226.3 million for the year ended December 31, 2016, a decrease of 0.8%.

During the years ended December 31, 2017 and 2016, our consolidated power plants generated 5,489,234 MWh and 5,396,959 MWh, respectively, an increase of 1.7%

For the year ended December 31, 2017, our Electricity segment generated approximately 67.6% of our total revenues (65.8% in 2016), while our Product segment generated approximately 32.4% of our total revenues (34.2% in 2016).

For the year ended December 31, 2017, approximately 85.3% of our Electricity segment revenues were 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 Heber 2 power plant in the Heber complex and the G2 power plant in the Mammoth complex, a total of between 30 and 40 MW, change primarily based on fluctuations in natural gas prices; and

- the prices paid for the electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii change primarily as a result of variations in the price of oil as well as other commodities.

Historically, we have entered into derivatives transactions to reduce our economic exposure to fluctuations in the price of natural gas and oil. We recently entered into a derivative transaction to reduce our economic exposure to fluctuations in the price of natural gas from February 2017 to December 2017. For the year ended December 31, 2017, we recorded a net loss of $0.4 million under Derivatives and foreign currency transaction gains (losses).

Revenues attributable to our Electricity segment are based on the sale of electricity generated by our geothermal and recovered energy-based power plants and, following the acquisition of our Viridity business during fiscal year 2017, the provision of energy storage, demand response and energy management services to our customers.

Revenues attributable to our Product segment are based on the sale of equipment, EPC contracts and the provision of various services to our customers. Product segment revenues may vary from period to period because of the timing of our receipt of purchase orders and the progress of our equipment manufacturing and execution of the relevant project.

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

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Trends and Uncertainties

Trends, factors and uncertainties may impact our operations and financial condition, including many that we do not or cannot foresee. However, we believe that our results of operations and financial condition for the foreseeable future will be primarily affected by the following trends, factors and uncertainties that are from time to time also subject to market cycles:

There has been increased demand for energy generated from geothermal and other renewable resources in the U.S. as costs for electricity generated from renewable resources have become more competitive. Much of this is attributable to legislative and regulatory requirements and incentives, such as state RPS and federal tax credits such as PTCs or ITCs (which are discussed in more detail in the section entitled “Government Grants and Tax Benefits” below). We believe that future demand for energy generated from geothermal and other renewable resources in the U.S. will be driven primarily by further commitment and implementation of state RPS and greenhouse gas initiatives.

We accelerated our efforts to expand business development activities in developing countries where geothermal is considered a local resource that can provide a stable and cost effective solution to increase access to power. We expect that a variety of local governmental initiatives will create new opportunities for the development of new projects with the potential to realize higher returns on our equity as well as to 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.

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. As a result of the operational improvements and technological advancements that were implemented and that we plan to continue to implement in our operating portfolio, including capacity additions, geographical expansion and re-contracting of existing power plants, we expect that the Electricity segment contribution to our operating income will increase further in the future. Due to the increasing contribution of our Electricity segment to our operating income compared to the contribution of our Product segment, and due to the nature of the Product segment where revenues are less stable, we are targeting to increase future revenues from our Electricity segment in order to increase revenues, profitability and stability. We also intend to continue to pursue opportunities as they arise in our recovered energy business, in the Solar PV sector, in the energy storage market and in other forms of clean energy. In addition, pursuant to our strategic plan, we acquired our Viridity business which operates in the energy storage, demand response and energy management markets and generates revenues derived primarily from software license fees and the provision of services. We are also pursuing PPAs with enterprises that will increase our potential customer base.

We have adopted a strategic plan for the growth of our company, in terms of geographic scope, customer base, and technology platforms covered by our product and service offerings, with a focus on increasing net income from operations. Under this plan, we will continue to focus on organic growth and increasing operational efficiency of our existing business lines. In addition, we are actively pursuing domestic and international acquisition opportunities, both within our existing business lines and the solar power generation and energy storage businesses, all of which are targeted as part of the plan. For example, we recently acquired our interest in the Bouillante geothermal power plant in Guadeloupe and signed a definitive agreement to acquire U.S. Geothermal Inc. (NYSE American: HTM), a renewable energy company focused on the development, production and sale of electricity from geothermal energy. We also completed the acquisition of our Viridity business during fiscal year 2017. As part of our services offering expansion through our Viridity business, we have developed our battery storage as a service ("BSAAS") strategy to provide comprehensive holistic solutions for energy storage, demand response, energy management through nimble and flexible business models, technology and product solutions. We plan to develop, build, own and operate energy storage facilities and provide related services in diversified markets. We will face a number of challenges and uncertainties in implementing this plan, including integration of recently acquired assets as well as potential new acquisitions, and we may revise elements of the plan in response to market conditions or other factors as we move forward with the plan.

In the Electricity segment, we expect intense domestic competition from the solar and wind power generation industries to continue and increase. While we believe the expected demand for renewable energy will be large enough to accommodate increased competition, any such increase in competition, including increasing amounts of renewable energy under contract as well as any further decline in natural gas prices attributable to increased production may contribute to a reduction in electricity prices. However, despite increased competition from the solar and wind power generation industries, we believe that firm and flexible base load electricity, such as geothermal-based energy, will continue to be an important source of renewable energy in areas with commercially viable geothermal resources. In the geothermal industry, we have experienced a decrease in the upfront fee required to secure geothermal leases largely as a result of reduced competition for such leases.

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

The 38 MW Puna complex has three PPAs, one of which (the 25 MW PPA) has a monthly variable energy rate based on the local utility’s avoided costs. A decrease in the price of oil as well as in other commodities will result in a decrease in the incremental cost that the power purchaser avoids by not generating its electrical energy needs from oil, which will result in a reduction of the energy rate that we may charge under this PPA. In order to reduce our exposure to oil we signed fixed rate PPAs for the remaining 13 MW.

The pricing under our PPAs for the G2 power plant in the Mammoth complex and Heber 2 power plant in the Heber complex for a total of between 30 MW and 40 MW is variable rate based on SRAC pricing that is impacted by natural gas prices. In 2016, we signed a fixed rate PPA that reduced our exposure to fluctuations in natural gas prices at the Ormesa complex starting in November 2017. In addition, to further reduce our exposure to natural gas prices, we enter, from time to time, into derivative transactions. In January 2017, we acquired put options with a strike price of $3.00 to hedge our exposure to decreasing natural gas prices to below $3.00 per MMBtu.

The amounts that we are paid under our PPAs for electricity, capacity and other energy attributes vary for a number of reasons, including:

market conditions when the PPA is signed;

the competitive environment in the power market where the power plant is located and the power and other energy attributes are sold; and

in the case of contracts described in the prior bullets with variable pricing components, current oil and natural gas prices.

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This means, among other things, that the average price per MWh, which is one of the metrics some investors may use to evaluate power plant revenues, can fluctuate from period to period. Based on total Electricity segment revenues (excluding revenues related to our Viridity business), we earned, on average, $84.80 and $80.80 per MWh in 2017 and 2016, respectively. Oil and natural gas prices, together with other factors that affect our Electricity segment revenues, could cause changes in our average price per MWh in the future.

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 well as hostilities that may arise in the countries we operate. As of the date of this annual report, those risks include security conditions in Israel, the partial privatization of the electricity sector in Guatemala and the political uncertainty currently prevailing in some of the countries in which we operate as further discussed above under "Risk Factors". Although we maintain among other things political risk insurance for most of our investments in foreign power plants to mitigate these risks, insurance does not provide complete coverage with respect to all such risks.

Turkey's geothermal market is one of the fastest growing markets in the geothermal industry worldwide, mainly due to governmental and regulatory support. Turkey is ranked seventh globally with an installed geothermal capacity of approximately 1,000 MW. Since 2006, we have supplied our state of the art binary equipment to over 20 projects in Turkey, which account for over 40% of the total installed geothermal capacity in Turkey as of December 2017. As a major equipment supplier in the Turkish geothermal market we are involved in a number of projects that are currently under construction and plan to continue our marketing efforts to secure new contracts. Our revenue exposure to the Turkish market is increasing and we expect higher exposure in 2018, as we signed a number of new contracts in Turkey. While we do not see any immediate impact from the failed coup in Turkey and the recent vote for the constitutional amendment bill on our business and operations, adverse economic developments in this region or a decline in government support for the development of geothermal power in the country could affect local demand for the geothermal equipment and services we provide or the prices we may charge for such equipment and services. We are monitoring any change in the political and business environments that may affect our future business and operations in the country.

We established a facility in Turkey in order to locally produce several power plant components that entitle our customers to increased incentives under the renewable energy laws. The use of local equipment in renewable energy based generating facilities in Turkey entitles such facilities to significant benefits under Turkish law, provided such facilities have obtained an RER Certificate from EMRA, which requires the issuance of a local certificate. If we do not obtain the local certificate, then some of our customers under the relevant supply agreements in Turkey may not be issued a RER Certificate based on the equipment we supply to them, and we will be required to make a payment to such customers equal to the amount of the expected lost benefit.

FERC is allowed under PURPA to terminate, upon the request of a utility, the obligation of the utility 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. FERC has granted the California investor-owned utilities a waiver of the mandatory purchase obligations from Qualifying Facilities above 20 MW. If the utilities in the regions in which our domestic power plants operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from us upon termination of the existing PPA, which could have an adverse effect on our revenues.

The Trump Administration has expressed skepticism regarding climate change. The final outcome of this Administration's policies and efforts regarding climate change and resulting effects to the geothermal industry remain uncertain.

While the recently enacted U.S. federal tax legislation (referred to herein as the Tax Act) reduces the corporate tax rate, it also contains provisions which may impact companies engaged in the renewable energy industry as well as companies with international operations, such as us. The Tax Act includes provisions that would impact eligibility to claim production tax credits, reduce the amount of production tax credits, and affect depreciation and interest deduction. Other provisions would change earnings stripping rules, potentially reduce the deductibility of cross-border payments (other than cost of goods sold), and impose a tax on unrepatriated foreign earnings. For example, among other things, the Tax Act (i) allows the cost of new or used equipment purchased from third parties to be "expensed" or deducted immediately; (ii) is likely to make some borrowing more expensive, as it denies interest deductions on debt starting in 2018 to the extent a company's net interest expense exceeds 30 percent of its adjusted taxable income; (iii) subjects U.S. corporations with offshore subsidiaries to a one-time U.S. tax on untaxed earnings in offshore holding companies as if the earnings had been brought back to the U.S., thereby triggering a tax; (iv) prohibits corporations from using net operating losses incurred after 2017 to reduce income by more than 80 percent in a year and from carrying such losses back two years as they have been allowed to do in the past; and (v) prohibits some cross-border interest and royalty payments to related companies from being deducted starting in 2018. We continue to examine the impact that the recently enacted tax legislation may have on our business and operations.

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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 85.3% of our Electricity revenues for the year ended December 31, 2017 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. Our SO#4 PPAs totaling approximately 50 MW in California are subject to the impact of fluctuations in natural gas prices, while the price paid for electricity pursuant to the 25 MW PPA for the Puna complex in Hawaii is impacted by the price of oil as well as other commodities. Accordingly, our revenues from those power plants may fluctuate.

Our Electricity segment revenues are also subject to seasonal variations, as more fully described in “Seasonality” below.

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

Revenues attributable to our Product segment fluctuate between periods, primarily based on our ability to receive customer orders, the status and timing of such orders, delivery of raw materials and the completion of manufacturing. Larger customer orders for our products are typically the result of our sales efforts, our participation in, and winning tenders or requests for proposals issued by potential customers in connection with projects they are developing as well as orders by returning customers. 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.

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

	Revenues (dollars in thousands)			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
Revenues:						
Electricity	$468,329	$436,292	$375,920	67.6 %	65.8 %	63.2 %
Product	224,483	226,299	218,724	32.4	34.2	36.8
Total revenues	$692,812	$662,591	$594,644	100.0%	100.0%	100.0%

Geographic Breakdown of Revenues

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

	Revenues in Thousands			% of Revenues for Period Indicated		
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
Electricity Segment:						
United States	$298,220	$288,842	$261,478	63.7 %	66.2 %	69.6 %
Foreign	170,109	147,450	114,442	36.3	33.8	30.4
Total	$468,329	$436,292	$375,920	100.0%	100.0%	100.0%
Product Segment:						
United States	$2,912	$18,183	$675	1.3 %	8.0 %	0.3 %
Foreign	221,571	208,116	218,049	98.7	92.0	99.7
Total	$224,483	$226,299	$218,724	100.0%	100.0%	100.0%

The contribution of our domestic and foreign operations within our Electricity segment and Product segment to combined pre-tax income differ in a number of ways.

Electricity Segment. Our Electricity segment domestic revenues were approximately 75% and 96% higher than our Electricity segment foreign revenues for the years ended December 31, 2017 and 2016, respectively. However, domestic operations in our Electricity segment have higher costs of revenues and expenses than the foreign operations in our Electricity segment. Our foreign power plants are located in lower-cost regions, like Kenya, Guatemala, Honduras and Guadeloupe, which favorably impact payroll and maintenance expenses among other items. They are also newer than most of our domestic power plants and therefore tend to have lower maintenance costs and higher availability factors than our domestic power plants.

Product Segment. Our Product segment foreign revenues were 99% and 92% of our total Product segment revenues for the years ended December 31, 2017 and 2016, respectively. Our Product segment foreign activity also benefits from lower costs of revenues and expenses than Product segment domestic activity such as lower labor and transportation costs. Accordingly, our Product segment foreign activity contributes more than our Product segment domestic activity to our pre-tax income from operations.

Relative Contributions. While our combined (domestic and foreign) Electricity segment revenues exceeded our combined Product segment revenues by approximately $243.8 million and $210.0 million for the years ended December 31, 2017 and 2016, respectively, Product segment revenues (that are primarily foreign) resulted in higher pre-tax income from foreign operations for both of those periods.

Seasonality

Electricity generation from some of our geothermal power plants is subject to seasonal variations; in the winter, our power plants produce more energy primarily attributable to the lower ambient temperature, which has a favorable impact on the energy component of our Electricity segment revenues. The prices (primarily for capacity) paid for electricity under the PPAs with Southern California Edison and PG&E in California for the Heber 2 power plant in the Heber complex, the Mammoth complex and the North Brawley power plant are higher in the months of June through September. The higher payments payable by Southern California Edison and PG&E in the summer months offset the negative impact on our revenues from lower generation in the summer attributable to the higher ambient temperature. As a result, we receive, and expect to continue to receive in the future, higher revenues from these power plants and complexes during such months.

Breakdown of Cost of Revenues

Electricity Segment

The principal cost of revenues attributable to our operating power plants includes operation and maintenance expenses comprised of salaries and related employee benefits, equipment expenses, costs of parts and chemicals, costs related to third-party services, lease expenses, royalties, startup and auxiliary electricity purchases, property taxes, insurance and, for some of our projects, purchases of make-up water for use in our cooling towers and also depreciation and amortization. In our California power plants our principal cost of revenues also includes transmission charges and scheduling charges. In some of our Nevada power plants we also incur transmission and wheeling 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 power 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 3.9% of Electricity segment revenues for the years ended December 31, 2017 and December 31, 2016, respectively.

Product Segment

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

Cash and Cash Equivalents

Our cash and cash equivalents, as of December 31, 2017, decreased to $47.8 million from $230.2 million as of December 31, 2016. This decrease is principally attributable to: (i) our use of $259.2 million to fund capital expenditures; (ii) repayment of $66.2 million of long-term debt; (iii) an investment in an unconsolidated company of $46.3 million; (iv) $35.3 million net cash paid for the acquisition of our Viridity business; (v) $21.3 million paid to noncontrolling interest; (vi) payment of a $20.5 million dividend; (vii) a net change in restricted cash and cash equivalents of $14.6 million; and (viii) $14.3 million of cash paid to prepay our OFC Senior Secured Notes. This decrease was partially offset by: (i) $245.6 million derived from operating activities during the year ended December 31, 2017; and (ii) net proceeds of $51.5 million from our revolving credit lines with commercial banks. As described below in "Liquidity and Capital Resources", our corporate borrowing capacity under committed lines of credit with different commercial banks as of December 31, 2017 was $468.0 million, of which we have utilized $330.2 million as of December 31, 2017.

Critical Accounting Estimates and Assumptions

Our significant accounting policies are more fully described in Note 1 to our consolidated financial statements set forth in Item 8 of this annual report. However, certain of our accounting policies are particularly important to an understanding of our financial position and results of operations. In applying these critical accounting estimates and assumptions, our management uses its judgment to determine the appropriate assumptions to be used in making certain estimates. Such estimates are based on management's historical experience, the terms of existing contracts, management's observance of trends in the geothermal industry, information provided by our customers and information available to management from other outside sources, as appropriate. Such estimates are subject to an inherent degree of uncertainty and, as a result, actual results could differ from our estimates. Our critical accounting policies include:

- *Revenues and Cost of Revenues.* Revenues related to the sale of electricity from our geothermal and REG power plants and capacity payments paid in connection with such sales (electricity revenues) are recorded based upon output delivered and capacity provided by such power plants at rates specified pursuant to the relevant PPAs. Revenues related to PPAs accounted for as operating leases with minimum lease rentals which vary over time are generally recognized on a straight-line basis over the term of the PPA. PPAs with contingent rentals are recognized when earned.

Revenues generated from the construction of geothermal and recovered energy-based power plant equipment and other equipment on behalf of third parties (product revenues) are recognized using the percentage of completion method, which requires estimates of future costs over the full term of product delivery. Such cost estimates are made by management based on prior operations and specific project characteristics and designs. If management's estimates of total estimated costs with respect to our Product segment are inaccurate, then the percentage of completion is inaccurate resulting in an over- or under-estimate of gross margins. As a result, we review and update our cost estimates on significant contracts on a quarterly basis, and at least on an annual basis for all others, or when circumstances change and warrant a modification to a previous estimate. Changes in job performance, job conditions, and estimated profitability, including those arising from the application of penalty provisions in relevant contracts and final contract settlements, may result in revisions to costs and revenues and are recognized in the period in which the revisions are determined. Provisions for estimated losses relating to contracts are made in the period in which such losses are determined. Revenues generated from engineering and operating services and sales of products and parts are recorded once the service is provided or product delivery is made, as applicable.

- *Property, Plant and Equipment.* We capitalize all costs associated with the acquisition, development and construction of power plant facilities. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. We estimate the useful life of our power plants to range between 25 and 30 years. Such estimates are made by management based on factors such as prior operations, the terms of the underlying PPAs, geothermal resources, the location of the assets and specific power plant characteristics and designs. Changes in such estimates could result in useful lives which are either longer or shorter than the depreciable lives of such assets. We periodically re-evaluate the estimated useful life of our power plants and revise the remaining depreciable life on a prospective basis.

We capitalize costs incurred in connection with the exploration and development of geothermal resources beginning when we acquire land rights to the potential geothermal resource. Prior to acquiring land rights, we make an initial assessment that an economically feasible geothermal reservoir is probable on that land using available data and external assessments vetted through our exploration department and occasionally outside service providers. Costs incurred prior to acquiring land rights are expensed. It normally takes two to three years from the time we start active exploration of a particular geothermal resource to the time we have an operating production well, assuming we conclude the resource is commercially viable.

In most cases, we obtain the right to conduct our geothermal development and operations on land owned by the BLM, various states or with private parties. In consideration for certain of these leases, we may pay an up-front non-refundable bonus payment which is a component of the competitive lease process. This payment and other related costs are capitalized and included in construction-in-process. Once we acquire land rights to the potential geothermal resource, we perform additional activities to assess the commercial viability of the resource. Such activities include, among others, conducting surveys and other analyses, obtaining drilling permits, creating access roads to drilling sites, and exploratory drilling which may include temperature gradient holes and/or slim holes. Such costs are capitalized and included in construction-in-process. Once our exploration activities are complete, we finalize our assessment as to the commercial viability of the geothermal resource and either proceed to the construction phase for a power plant or abandon the site. If we decide to abandon a site, all previously capitalized costs associated with the exploration project are written off.

Our assessment of economic viability of an exploration project involves significant management judgment and uncertainties as to whether a commercially viable resource exists at the time we acquire land rights and begin to capitalize such costs. As a result, it is possible that our initial assessment of a geothermal resource may be incorrect and we will have to write off costs associated with the project that were previously capitalized. For example, during the years ended December 31, 2017 and 2016, we determined that the geothermal resource at four and three of our exploration projects, respectively, would not support commercial operations and as such, we discontinued exploration activities at those sites. As a result of this determination, we expensed \$1.8 million and \$3.0 million of capitalized costs during the years ended December 31, 2017 and 2016, respectively. Due to the uncertainties inherent in geothermal exploration, these historical impairments may not be indicative of future impairments. Included in construction-in-process are costs related to projects in exploration and development of \$63.9 million and \$54.4 million at December 31, 2017 and 2016, respectively. Included in these amounts at December 31, 2017 and 2016, respectively, are \$17.0 million and \$17.4 million that relate to up-front bonus payments.

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- *Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of.* We evaluate long-lived assets, such as property, plant and equipment and construction-in-process for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Factors which could trigger an impairment include, among others, significant underperformance relative to historical or projected future operating results, significant changes in our use of assets or our overall business strategy, negative industry or economic trends, a determination that an exploration project will not support commercial operations, a determination that a suspended project is not likely to be completed, a significant increase in costs necessary to complete a project, legal factors relating to our business or when we conclude that it is more likely than not that an asset will be disposed of or sold.

We test our operating plants that are operated together as a complex for impairment at the complex level because the cash flows of such plants result from significant shared operating activities. For example, the operating power plants in a complex are managed under a management combined operation generally with one central control room that controls and one maintenance group that services all of the power plants in a complex. As a result, the cash flows from individual plants within a complex are not largely independent of the cash flows of other plants within the complex. We test for impairment of our operating plants which are not operated as a complex, as well as our projects under exploration, development or construction that are not part of an existing complex, at the plant or project level. To the extent an operating plant becomes part of a complex in the future, we will test for impairment at the complex level.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to the estimated future net undiscounted cash flows expected to be generated by the asset. The significant assumptions that we use in estimating our undiscounted future cash flows include (i) projected generating capacity of the power plant and rates to be received under the respective PPA and (ii) projected operating expenses of the relevant power plant. Estimates of future cash flows used to test recoverability of a long-lived asset under development also include cash flows associated with all future expenditures necessary to develop the asset. If future cash flows are less than the assumptions we used in such estimates, we may incur impairment losses in the future that could be material to our financial condition and/or results of operations.

If our assets are considered to be impaired, the impairment to be recognized is the amount by which the carrying amount of the assets exceeds their fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. We believe that for the year ended December 31, 2017, no impairment exists for any of our long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. Estimates of the fair value of assets require estimating useful lives and selecting a discount rate that reflects the risk inherent in future cash flows.

- *Obligations Associated with the Retirement of Long-Lived Assets.* We record the fair market value of legal liabilities related to the retirement of our assets in the period in which such liabilities are incurred. These liabilities include our obligation to plug wells upon termination of our operating activities, the dismantling of our power plants upon cessation of our operations, and the performance of certain remedial measures related to the land on which such operations were conducted. When a new liability for an asset retirement obligation is recorded, we capitalize the costs of such liability by increasing the carrying amount of the related long-lived asset. Such liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. At retirement, we either settle the obligation for its recorded amount or report either a gain or a loss with respect thereto. Estimates of the costs associated with asset retirement obligations are based on factors such as prior operations, the location of the assets and specific power plant characteristics. We review and update our cost estimates periodically and adjust our asset retirement obligations in the period in which the revisions are determined. If actual results are not consistent with our assumptions used in estimating our asset retirement obligations, we may incur additional losses that could be material to our financial condition or results of operations.

- *Accounting for Income Taxes.* Significant estimates are required to arrive at our consolidated income tax provision and other tax balances. This process requires us to estimate our actual current tax exposure and to make an assessment of temporary differences resulting from differing treatments of items for tax and accounting purposes. Such differences result in deferred tax assets and liabilities which are included in our consolidated balance sheets. For those jurisdictions where the projected operating results indicate that realization of our net deferred tax assets is not more likely than not, a valuation allowance is recorded.

We evaluate our ability to utilize the deferred tax assets quarterly and assess the need for the valuation allowance. In assessing the need for a valuation allowance, we estimate future taxable income, including the impacts of the passing of the recently enacted Tax Act, considering the feasibility of ongoing tax planning strategies and the realization of tax credits and tax loss carryforwards. Valuation allowances related to deferred tax assets can be affected by changes in tax laws, statutory tax rates, and future taxable income. We have recorded a partial valuation allowance related to our U.S. deferred tax assets. In the future, if there is sufficient evidence that we will be able to generate sufficient future taxable income in the U.S., we may be required to reduce this valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

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In the ordinary course of business, there is inherent uncertainty in quantifying our income tax positions. We assess our income tax positions and record tax benefits for all years subject to examination based upon management's evaluation of the facts, circumstances and information available at the reporting date. For those tax positions where it is more likely than not that a tax benefit will be sustained, which is greater than 50% likelihood of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information, we recognize between 0 to 100% of the tax benefit. For those income tax positions where it is not more likely than not that a tax benefit will be sustained, we do not recognize any tax benefit in the consolidated financial statements. Resolution of these uncertainties in a manner inconsistent with our expectations could have a material impact on our financial condition or results of operations.

New Accounting Pronouncements

See Note 1 to our consolidated financial statements set forth in Item 8 of this annual report for information regarding new accounting pronouncements.

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Results of Operations

The following table sets forth our historical operating results for the periods ended and at the dates indicated. We have derived the financial data for the years ended December 31, 2017, 2016 and 2015 from our audited condensed consolidated financial statements set forth in Part II, Item 8 of this annual report. Such consolidated financial data reflects the correction of certain prior period errors related to income taxes, as more fully described in Note 1 to our consolidated financial statements, which resulted in the restatement of our financial statements as of and for the year ended December 31, 2017 and the revision of our financial statements as of and for the year ended December 31, 2016 and the year ended December 31, 2015.

Our historical operating results in dollars and as a percentage of total revenues are presented below. A comparison of the different years described below may be of limited utility due to (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.

	Year Ended December 31,		
	2017 (As restated)	**2016**	**2015**
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$468,329	$436,292	$375,920
Product	224,483	226,299	218,724
	692,812	662,591	594,644
Cost of revenues:			
Electricity	272,266	261,573	242,612
Product	152,094	130,223	133,753
	424,360	391,796	376,365
Gross profit			
Electricity	196,063	174,719	133,308
Product	72,389	96,076	84,971
	268,452	270,795	218,279
Operating expenses:			
Research and development expenses	3,157	2,762	1,780
Selling and marketing expenses	15,600	16,424	16,077
General and administrative expenses	42,881	46,710	34,782
Write-off of unsuccessful exploration activities	1,796	3,017	1,579
Operating income	205,018	201,882	164,061
Other income (expense):			
Interest income	988	971	297
Interest expense, net	(54,142)	(67,389)	(72,577)
Derivatives and foreign currency transaction gains (losses)	2,654	(5,534)	(1,622)

Income attributable to sale of tax benefits	17,878	16,503	25,431
Other non-operating expense, net	(1,666)	(5,345)	(1,991)
Income from continuing operations before income taxes and equity in losses of investees	170,730	141,088	113,599
Income tax (provision) benefit	(21,664)	(37,059)	16,057
Equity in earnings (losses) of investees, net	(1,957)	(7,735)	(5,508)
Net income	147,109	96,294	124,148
Net income attributable to noncontrolling interest	(14,695)	(7,586)	(3,776)
Net income attributable to the Company's stockholders	$132,414	$88,708	$120,372
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$2.64	$1.79	$2.48
Diluted:			
Net income	$2.61	$1.77	$2.45
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,110	49,469	48,562
Diluted	50,769	50,140	49,187

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	Year Ended December 31,		
	2017 (As restated)	2016	2015
Revenues:			
Electricity	67.6 %	65.8 %	63.2 %
Product	32.4	34.2	36.8
	100.0	100.0	100.0
Cost of revenues:			
Electricity	58.1	60.0	64.5
Product	67.8	57.5	61.2
	61.3	59.1	63.3
Gross profit			
Electricity	41.9	40.0	35.5
Product	32.2	42.5	38.8
	38.7	40.9	36.7
Operating expenses:			
Research and development expenses	0.5	0.4	0.3
Selling and marketing expenses	2.3	2.5	2.7
General and administrative expenses	6.2	7.0	5.8
Write-off of unsuccessful exploration activities	0.3	0.5	0.3
Operating income	29.6	30.5	27.6
Other income (expense):			
Interest income	0.1	0.1	0.0
Interest expense, net	(7.8)	(10.2)	(12.2)
Derivatives and foreign currency transaction gains (losses)	0.4	(0.8)	(0.3)
Income attributable to sale of tax benefits	2.6	2.5	4.3
Other non-operating expense, net	(0.2)	(0.8)	(0.3)
Income from continuing operations before income taxes and equity in losses of investees	24.6	21.3	19.1
Income tax (provision) benefit	(3.1)	(5.6)	2.7
Equity in earnings (losses) of investees, net	(0.3)	(1.2)	(0.9)
Net income	21.2	14.5	20.9
Net income attributable to noncontrolling interest	(2.1)	(1.1)	(0.7)
Net income attributable to the Company's stockholders	19.1 %	13.4 %	20.2 %

Comparison of the Year Ended December 31, 2017 and the Year Ended December 31, 2016

Total Revenues

Total revenues for the year ended December 31, 2017 were $692.8 million, compared to $662.6 million for the year ended December 31, 2016, representing a 4.6% increase from the prior period. This increase was attributable to our Electricity segment, in which revenues increased by 7.3% compared to the corresponding period in 2016.

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Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2017, were $468.3 million, compared to $436.3 million for the year ended December 31, 2016, representing a 7.3% increase from the prior period. This increase was primarily attributable to: (i) the full year consolidation of our Bouillante power plant in Guadeloupe, effective July 5, 2016, with revenues of $21.7 million for the year ended December 31, 2017, compared to $8.1 million for the year ended December 31, 2016; (ii) the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, with revenues of $10.0 million for the year ended December 31, 2017 and of our Tungsten Mountain power plant in Nevada, effective December 2017, with revenues of $2.2 million for the year ended December 31, 2017; (iii) an increase in generation at our Puna power plant attributable to successful improvement of the resource performance; and (iv) $2.7 million generated by our Viridity business from the provision of energy storage and demand response services. The increase was partially offset by a decrease in generation at some of our power plants that we had scheduled to take offline to address maintenance issues.

Power generation in our power plants increased by 1.7% from 5,396,959 MWh in the year ended December 31, 2016 to 5,489,234 MWh in the year ended December 31, 2017, primarily because of an increase in generation at our Puna power plant, the consolidation of our Bouillante power plant in Guadeloupe, and the commencement of operations of our Platanares power plant in Honduras and Tungsten Mountain power plant in Nevada, partially offset by a decrease in generation in some of our power plants mainly due to scheduled outages.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2017 were $224.5 million, compared to $226.3 million for the year ended December 31, 2016, representing a 0.8% decrease from the prior period. The slight decrease in our Product segment revenues was primarily attributable to completion or near-completion of our contracts for the Cerro Pabellon geothermal power plant in Chile, the Sarulla geothermal power plant in Indonesia, and other projects in Turkey, which were completed during 2016. This decrease was partially offset by revenue recognition from two new geothermal projects in New Zealand and China (on which we started construction in the first quarter of 2017) and new projects in Turkey in the amounts of $31.7 million, $23.1 million and $121.3 million, respectively.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2017 was $424.4 million, compared to $391.8 million for the year ended December 31, 2016, representing a 8.3% increase from the prior period. This increase was attributable to an increase in cost of revenues from both the Electricity and Product segments. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2017 increased to 61.3%, compared to 59.1% for the year ended December 31, 2016. This increase was mainly attributable to an increase in cost of revenues as a percentage of total revenues in our Product segment.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2017 was $272.3 million, compared to $261.6 million for the year ended December 31, 2016, representing a 4.1% increase from the prior period. This increase was primarily attributable to additional cost of revenues from the consolidation of our Bouillante power plant in Guadeloupe, effective July 5, 2016, the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, as well as cost of revenues in the amount of $5.4 million related to our energy storage and demand response activity of our Viridity business. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2017 was 58.1%, compared to 60.0% for the year ended December 31, 2016. This decrease was primarily attributable to higher efficiency in some of our operating power plants.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2017 was $152.1 million, compared to $130.2 million for the year ended December 31, 2016, representing a 16.8% increase from the prior period. This increase was primarily attributable to additional costs associated with our project in Chile, as well as a different product mix and different margins in the various sales contracts we entered into for the Product segment during these periods. As a percentage of total Product segment revenues, our total cost of revenues attributable to the Product segment for the year ended December 31, 2017 was 67.8%, compared to 57.5% for the year ended December 31, 2016.

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Research and Development Expenses

Research and development expenses for the year ended December 31, 2017 were $3.2 million, compared to $2.8 million for the year ended December 31, 2016.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2017 were $15.6 million, compared to $16.4 million for the year ended December 31, 2016. This decrease was primarily due to lower sales commissions related to our Product segment because of a different commissions mix. Selling and marketing expenses for the year ended December 31, 2017 constituted 2.3% of total revenues for such year, compared to 2.5% of such revenues for the year ended December 31, 2016.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2017 were $42.9 million, compared to $46.7 million for the year ended December 31, 2016. This decrease was mainly due to (i) $11.0 million of expenses in the year ended December 31, 2016 related to the settlement of a qui tam claim and (ii) a $2.1 million adjustment in respect of an earn out related to the acquisition of our Viridity business, partially offset by (i) a $2.1 million charge for stock-based compensation expense associated with the acceleration of the vesting period of the stock options previously held by our CEO and CFO and exercised in connection with ORIX's acquisition of approximately 22% of our shares of common stock; (ii) general and administrative expenses related to our Viridity business; and (iii) $2.5 million in costs associated with the ORIX transaction and other acquisitions and sales activities in the year ended December 31, 2017. General and administrative expenses for the year ended December 31, 2017, excluding the one-time charge of $2.1 million for stock-based compensation, constituted 5.9% of total revenues for the year ended December 31, 2017, compared to 5.5%, excluding the one-time charge of $11.0 million related to the settlement mentioned above, of total revenues for the year ended December 31, 2016.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2017 was $1.8 million, compared to $3.0 million for the year ended December 31, 2016. The write-off of unsuccessful exploration activities for the year ended December 31, 2017 included costs related to the Glass Buttes site in Oregon, which we determined in the fourth quarter of 2017 would not support commercial operations. The majority of the write-off of unsuccessful exploration activities for the year ended December 31, 2016 consisted of costs related to the Twilight site in Oregon and a concession in Chile, which we determined would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2017 was $205.0 million, compared to $201.9 million for the year ended December 31, 2016, representing a 1.6% increase from the prior period. The increase in operating income was primarily attributable to the increase in our gross margin in our Electricity segment primarily as a result of the increase in revenues and higher efficiency in some of our operating power plants, and the decrease in general and administrative expenses, as discussed above. The increase was partially offset by a decrease in our gross margin in our Product segment, also discussed above. Operating income attributable to our Electricity segment for the year ended December 31, 2017 was $154.5 million, compared to $126.8 million for the year ended December 31, 2016. Operating income attributable to our Product segment for the year ended December 31, 2017 was $50.5 million, compared to $75.1 million for the year ended December 31, 2016.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2017 was $54.1 million, compared to $67.4 million for the year ended December 31, 2016, representing a 19.7% decrease from the prior period. This decrease was primarily due to: (i) the repayment, in September 2016, of $250 million of our senior unsecured bonds which bore interest at a fixed rate of 7% per annum, through the issuance of $67 million and $137 million, respectively of two new series of senior unsecured bonds, which bear interest at a fixed rate of 3.7% and 4.45% per annum, respectively, as discussed below; (ii) lower interest expense as a result of principal payments of long term debt and revolving credit lines with banks; and (iii) a $3.9 million decrease related to an increase in interest capitalized to projects, partially offset by the December 2016 issuance of senior secured notes issued by our subsidiary that owns phase 1 of the Don A. Campbell power plant.

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Derivatives and Foreign Currency Transaction Gains (Losses)

Derivatives and foreign currency transaction gains for the year ended December 31, 2017 were $2.7 million, compared to losses of $5.5 million for the year ended December 31, 2016. Derivatives and foreign currency transaction gains for the year ended December 31, 2017 were attributable primarily to gains from foreign currency forward contracts, which were not accounted for as hedge transactions. Derivatives and foreign currency transaction losses for the year ended December 31, 2016 were primarily attributable to $2.6 million in losses from future contracts entered into to reduce our economic exposure to fluctuations in prices of natural gas and oil under our SO#4 and Puna PPAs, which were not accounted for as hedge transactions, and $1.5 million in losses due to changes in the fair value of the contract obligation in relating to the acquisition of our interest in the Bouillante power plant in Guadeloupe.

Income Attributable to Sale of Tax Benefits

Income attributable to the sale of tax benefits to institutional equity investors (as described below under “OPC Transaction”, “ORTP Transaction” and “Opal Geo Transaction”) for the year ended December 31, 2017 was $17.9 million, compared to $16.5 million for the year ended December 31, 2016. This income primarily represents the value of PTCs and taxable income or loss generated by Opal Geo and ORTP and allocated to investors in the year ended December 31, 2017 compared to PTCs and taxable income or loss generated by ORTP and OPC and allocated to investors in the year ended December 31, 2016.

Other Non-Operating Expense, Net

Other non-operating expense, net for the year ended December 31, 2017 was $1.7 million, compared to $5.4 million for the year ended December 31, 2016. Other non-operating expense, net for the year ended December 31, 2017 includes a make whole premium of $1.9 million resulting from the prepayment of $14.3 million aggregate principal amount of our OFC Senior Secured Notes and $11.8 million aggregate principal amount of our DEG Loan (as described below). Other non-operating expense, net for the year ended December 31, 2016 includes: (i) prepayment fees of approximately $5.0 million due to the repayment of our senior unsecured bonds in September 2016 and (ii) a make whole premium of $0.6 million resulting from the repurchase of $6.8 million aggregate principal amount of our OFC Senior Secured Notes.

Income from operations, before income taxes and equity in losses of investees

Income from operations, before income taxes and equity in losses of investees for the year ended December 31, 2017 was $170.7 million, compared to $141.1 million for the year ended December 31, 2016, representing a 21.0% increase from the prior period. The income is primarily attributable to our foreign operations. This increase was driven by the increase in our domestic operations resulting mainly from the $11.0 million one-time expense in the year ended December 31, 2016 related to the settlement of a qui tam claim, approximately $5.0 million due to the repayment of the senior unsecured bonds in September 2016 and the associated decrease in interest expense, as described above.

Income Taxes

Income tax provision for the year ended December 31, 2017 was $21.7 million, compared to $37.1 million for the year ended December 31, 2016. The decrease in income tax provision from $37.1 million in the year ended December 31, 2016 to $21.7 million in the year ended December 31, 2017, primarily resulted from the increase in income before taxes in jurisdictions outside of the U.S., withholding tax on distribution of earnings, changes in valuation allowance and the impact of the U.S. tax reform legislation. Our effective tax rate for the years ended December 31, 2017 and 2016, was 12.7% and 26.3%, respectively. Our effective tax rate is principally based upon the composition of the income in different countries, the impact of U.S. tax reform legislation and changes related to valuation allowances for certain countries. Our aggregate effective tax rate is lower than the 35% U.S federal statutory tax rate due to: (i) as a substantial portion of our income is derived in Israel which is taxed at the corporate tax rate of 16%, partially offset by taxes on earnings in Kenya which are taxed at statutory rate of 37.5%; (ii) a tax credit and tax exemption related to the Company’s subsidiaries in Guatemala and Honduras; (iii) a partial valuation allowance release against the Company's U.S. deferred tax assets offset by withholding taxes; and (iv) impacts of U.S. tax reform legislation, specifically the remeasurement of deferred taxes and the inclusion in taxable income of the amount of certain repatriated earnings of foreign subsidiaries (see Note 18 to our consolidated financial statements set forth in Item 8 of this annual report for further details regarding the Company's income tax provision and the Tax Act).

For the year ended December 31, 2017 and 2016, we recorded a valuation allowance in the amount of approximately $77.6 million and $116.2 million, respectively, against our unutilized Federal tax credits (FTCs, PTCs and ITCs) and U.S. deferred tax assets related to net operating loss (NOL) carryforwards. As of December 31, 2017, we had U.S. federal NOLs in the amount of approximately $190.0 million, state NOLs in the amount of approximately $238.1 million and unutilized tax credits of approximately $172.2 million, all of which can be carried forward for 10-20 years. The related deferred tax assets totaled approximately $135.0 million. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration starting in 2027 of the NOL carryforwards and tax credits. The scheduled reversal of deferred tax liabilities, projected future taxable income, estimated impacts of tax reform and tax planning strategies were considered in determining the amount of valuation allowance. A valuation allowance in the amount of $77.6 million was recorded against the U.S. deferred tax assets as of December 31, 2017 because we believe it is more likely than not that the deferred tax assets will not be realized. If sufficient additional evidence of our ability to generate taxable income is established, we may be required to reduce or fully release the valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

Equity in losses of investees, net

Equity in losses of investees, net in the year ended December 31, 2017 was $2.0 million, compared to $7.7 million in the year ended December 31, 2016. Equity in losses of investees, net derived from our 12.75% share in the losses of the Sarulla project and from profits elimination.

Net Income

Net income for the year ended December 31, 2017 was $147.1 million, compared to $96.3 million for the year ended December 31, 2016, representing an increase of $50.8 million from the prior period. This increase in net income was primarily attributable to $11.0 million in one-time general and administrative expenses in the year ended December 31, 2016 related to the settlement of a qui tam claim, a decrease in interest expense of $13.2 million and a decrease in income taxes of $15.4 million, each as discussed above.

Comparison of the Year Ended December 31, 2016 and the Year Ended December 31, 2015

Total Revenues

Total revenues for the year ended December 31, 2016 were $662.6 million compared to $594.6 million for the year ended December 31, 2015, representing a 11.4%increase from the prior period. This increase was attributable to both our Electricity and Product segments, in which revenues increased by 16.1% and 3.5%, respectively, compared to the corresponding period in 2015.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2016 were $436.3 million, compared to $375.9 million for the year ended December 31, 2015, representing a 16.1% increase from the prior period. This increase was primarily attributable to: (i) the commencement of operations of the second phase of the McGinness Hills and Don A. Campbell power plants in Nevada in February 2015 and September 2015, respectively, as well as the commencement of operations of our Plant 4 at the Olkaria III complex in Kenya in January 2016; (ii) higher energy rates under the Heber 1 PPA commencing in December 2015, and (iii) the consolidation of our Bouillante power plant in Guadeloupe, effective July 5, 2016, following the acquisition of an approximately 60%

equity interest in GB. The increase was partially offset by a reduction in revenues generated by some of our power plants due to lower oil and natural gas prices.

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Power generation in our power plants increased by 11.6% from 4,835,109 MWh in the year ended December 31, 2015 to 5,396,959 MWh in the year ended December 31, 2016, mainly due to commencement of commercial operation of the second phase of the McGinness Hills power plant and Don A. Campbell power plant in Nevada, and the commencement of operations of our Plant 4 at the Olkaria III complex in Kenya.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2016 were $226.3 million, compared to $218.7 million for the year ended December 31, 2015, representing a 3.5% increase from the prior period. The increase in our Product segment revenues was primarily due to the start of revenue recognition from a new geothermal project we built. We recognized approximately $58 million of revenue from this project in the year ended December 31, 2016, compared to approximately $34 million in the year ended December 31, 2015. The total contract price for the project is approximately $99.0 million and it is scheduled to be completed in the first half of 2017. The increase was partially offset by a net decrease of approximately $11 million in revenues from projects we built in Turkey, of which some were completed in the year ended December 31, 2015, and due to timing of revenue recognition and different product mix.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2016 was $391.8 million, compared to $376.4 million for the year ended December 31, 2015, representing a 4.1% increase from the prior period. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2016 decreased to 59.1%, compared to 63.3% for the year ended December 31, 2015.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2016 was $261.6 million, compared to $242.6 million for the year ended December 31, 2015, representing a 7.8% increase from the prior period. This increase was primarily due to: (i) additional cost of revenues from the second phase of the McGinness Hills and Don A. Campbell power plants, the commencement of operations of our Plant 4 at the Olkaria III complex, and the consolidation of our Bouillante power plant all discussed above; and (ii) reimbursement of $2.5 million of mining tax imposed on us based on an audit performed by the state of Nevada for the years ended December 31, 2008, 2009 and 2010 following our successful appeal of the audit decision in the first quarter of 2015. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2016 was 60.0%, compared to 64.5% for the year ended December 31, 2015. This decrease was primarily due to higher efficiency in some of our operating power plants as well as lower costs of operating the three new power plants mentioned above.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2016 was $130.2 million, compared to $133.8 million for the year ended December 31, 2015, representing a 2.6% decrease from the prior period. This decrease was primarily attributable to efficiencies, cost savings and project management, offset partially due to the increase in Product segment revenues as discussed above. As a percentage of total Product segment revenues, our total cost of revenues attributable to the Product segment for the year ended December 31, 2016 was 57.5%, compared to 61.2% for the year ended December 31, 2015. This decrease was mainly attributable to improvements made at our manufacturing facility and our project management and construction costs as well as the different product mix and different margins in the various sales contracts we entered into for this segment during these periods.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2016 were $2.8 million, compared to $1.8 million for the year ended December 31, 2015.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2016 were $16.4 million, compared to $16.1 million for the year ended December 31, 2015. Selling and marketing expenses for the year ended December 31, 2016 constituted 2.5% of total revenues for such year, compared to 2.7% of such revenues for the year ended December 31, 2015.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2016 were $46.7 million, compared to $34.8 million for the year ended December 31, 2015. This increase was mainly due to $11.0 million expenses related to a settlement with certain of our former employees to settle claims brought by such employees against us under qui tam provisions of the False Claims Act, partially offset by $3.8 million of expenses related to the share exchange with Ormat Industries, recorded in the first quarter of 2015. General and administrative expenses excluding the one-time costs and the costs related to the share exchange, constituted 5.5% and 5.2% of total revenues for the years ended December 31, 2016 and 2015, respectively.

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2016 was $3.0 million compared to $1.6 million for the year ended December 31, 2015. The majority of the write-off of unsuccessful exploration activities for the year ended December 31, 2016 represented the costs related to the Twilight site in Oregon and concession in Chile, which we determined would not support commercial operation. The majority of the write-off of unsuccessful exploration activities for the year ended December 31, 2015 represented the costs related to the Maui prospect in Hawaii, which we determined in the fourth quarter of 2015 would not support commercial operations.

Operating Income

Operating income for the year ended December 31, 2016 was $201.9 million, compared to $164.1 million for the year ended December 31, 2015, representing a 23.1% increase from the prior period. The increase in operating income was primarily attributable to the increase in our gross margin in both our Electricity and Product segments primarily due to the increase in revenues, as discussed above, partially offset by $11.0 million one-time expenses related to a settlement with certain of our former employees of a claims brought by such employees against us under qui tam provisions of the False Claim Act. Operating income attributable to our Electricity segment for the year ended December 31, 2016 was $126.8 million, compared to $99.3 million for the year ended December 31, 2015. Operating income attributable to our Product segment for the year ended December 31, 2016 was $75.1 million, compared to $64.7 million for the year ended December 31, 2015.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2016 was $67.4 million, compared to $72.6 million for the year ended December 31, 2015, representing a 7.1% decrease from the prior period. This decrease was primarily due to: (i) the repayment, in September 2016, of the senior unsecured bonds in the amount of $250 million which bore interest at a fixed rate of 7% per annum, by issuance of new series of senior unsecured bonds in the amounts of $67 million and $137 million, respectively which bear interest at a fixed rate of 3.7% and 4.45% per annum, respectively, as discussed below; and (ii) a lower interest expense as a result of principal payments of long term debt and revolving credit lines with banks; partially offset due to $0.8 million decrease related to interest capitalized to projects.

Derivatives and Foreign Currency Transaction Losses

Derivatives and foreign currency transaction losses for the year ended December 31, 2016 were $5.5 million, compared to $1.6 million for the year ended December 31, 2015. Derivatives and foreign currency transaction losses for the year ended December 31, 2016 were attributable primarily to $2.6 million in losses from future contracts to reduce our economic exposure to fluctuations in prices of natural gas and oil under our SO#4 and Puna PPAs, which were not accounted for as hedge transactions, and $1.5 million in losses due to changes in the fair value of the contract obligation in the Guadeloupe transaction. Derivatives and foreign currency transaction losses for the year ended December 31, 2015 were attributable primarily to losses on foreign currency forward contracts, 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 below under “OPC Transaction” and “ORTP Transaction”) for the year ended December 31, 2016 was $16.5 million, compared to $25.4 million for the year ended December 31, 2015. This income represents mainly the value of PTCs and taxable income or loss generated by ORTP and allocated to investors. This decrease was primarily attributable to a lower taxable loss in ORTP.

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Other non-operating income (loss)

Other non-operating loss for the year ended December 31, 2016 was $5.4 million, compared to $2.0 million in the year ended December 31, 2015. Other non-operating loss for the year ended December 31, 2016 includes: (i) prepayment fees of approximately $5.0 million due to the repayment of the senior unsecured bonds in September 2016, as discussed below; and (ii) a premium of $0.6 million related to the repurchase of $6.8 million aggregate principal amount of our OFC Senior Secured Notes. Other non-operating loss for the year ended December 31, 2015 includes a capital loss of $1.7 million resulting from the repurchase of $30.6 million aggregate principal amount of our OFC Senior Secured Notes.

Income from operations, before income taxes and equity in losses of investees

Income from operations, before income taxes and equity in losses of investees for the year ended December 31, 2016 was $141.1 million, compared to $113.6 million for the year ended December 31, 2015, representing a 24.2% increase from the prior period. This income is attributable in total to our foreign operations. The increase compared to the year ending December 31, 2015 was driven by the increase in Product Segment revenues in Indonesia and Chile. The small loss in our domestic operations resulted mainly from the $11.0 million one-time expenses related to a settlement with certain of our former employees of claims brought by such employees against us under qui tam provisions of the False Claim Act and the approximately $5.0 million due to the repayment of the senior unsecured bonds in September 2016.

Income Taxes

Income tax provision for the year ended December 31, 2016 was $37.1 million, compared to income tax benefit of $16.1 million for the year ended December 31, 2015. Income tax benefit for the year ended December 31, 2015 includes a $49.4 million deferred tax asset relating to the release of the valuation allowance for the additional 50% investment deduction for our Olkaria 3 power plant based on amendments to the Kenya Income Tax Act that came into effect on September 11, 2015 and which extended the period to utilize such investment deduction from five years to ten years. Income tax provision for the year ended December 31, 2015, excluding the $49.4 million, was $33.3 million. The increase in income tax provision from $33.3 million, excluding the $49.4 million, in the year ended December 31, 2015 to $41.7 million, excluding $4.7 million of tax benefit pertaining to our operations in Kenya (see Note 18 to our consolidated financial statements set forth in Item 8 of this annual report) in the year ended December 31, 2016, primarily resulted from the increase in income before taxes in jurisdictions outside the U.S. Our effective tax rate for the years ended December 31, 2016, and 2015 (excluding the $49.4 million), was 26.3% and 29.6%, respectively. Our effective tax rate is principally based upon the composition of the income in different countries and changes related to valuation allowances for certain countries. Our aggregate effective tax rate is lower than the 35% U.S federal statutory tax rate as a substantial portion of our income is derived in Israel which is taxed at the corporate tax rate of 16%, partially offset by taxes on earnings in Kenya which are taxed at statutory rate of 37.5%. There is no impact on the Company’s income tax expense (benefit) related to the U.S. earnings (losses) due to the offsetting impact on the provision related to the change in the valuation allowance on the Company’s U.S. net deferred tax asset position.

For the year ended December 31, 2016 and 2015, we recorded a valuation allowance in the amount of approximately $116.2 million and $92.9 million respectively, against our U.S. deferred tax assets related to net operating loss (NOL) carryforwards and unutilized tax credits (PTCs and ITCs). As of December 31, 2016, we had U.S. federal NOLs in the amount of approximately $331.5 million, state NOLs in the amount of approximately $231.1 million, and unutilized tax credits of approximately $83.1 million, all of which can be carried forward for 20 years. The related deferred tax assets totaled approximately $116.2 million. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration starting in 2027 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 valuation allowance in the amount of $116.2 million was recorded against the U.S. deferred tax assets as of December 31, 2016 because we believe it is more likely than not that the deferred tax assets will not be realized. If sufficient additional evidence of our ability to generate taxable income is established, we may be required to reduce or fully release the valuation allowance, resulting in income tax benefits in our consolidated statement of operations.

Equity in losses of investees, net

Equity in losses of investees, net in the year ended December 31, 2016 was $7.7 million, compared to $5.5 million in the year ended December 31, 2015. Equity in losses of investees, net derived from our 12.75% share in the losses of the Sarulla project and from profits elimination.

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Net Income

Net income for the year ended December 31, 2016 was $96.3 million, compared to $124.1 million for the year ended December 31, 2015, representing a decrease of $27.8 million from the prior period. This decrease in net income was primarily attributable to $11.0 million in one-time general and administrative expenses related to the settlement paid in connection with the FCA claim, as discussed above, the $53.2 million increase in income tax provision, a decrease of $8.9 million in income attributable to sale of tax benefits, and $3.4 million increase in other non-operating loss, partially offset by an increase of $52.5 million in gross margin and a decrease in interest expense of $5.2 million, all as discussed above.

Liquidity and Capital Resources

Our principal sources of liquidity are cash flows from operations, proceeds from third party debt such as borrowings under our credit facilities and private offerings and issuances of debt securities, project financing, tax monetization transactions, short term borrowing under our lines of credit, and proceeds from the sale of equity interests in one or more of our projects. We have utilized this cash to develop and construct power plants, fund our acquisitions, pay down existing outstanding indebtedness, and meet our other cash and liquidity needs.

As of December 31, 2017, we had access to the following sources of funds: (i) $47.8 million in cash and cash equivalents, of which $25.0 million was held by our foreign subsidiaries; and (ii) $107.9 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2018 include approximately $300.0 million for capital expenditures on new projects under development or construction including storage projects, exploration activity and maintenance capital expenditures for our existing projects, as well as $109.0 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; and (iii) future project financing and refinancing (including construction loans). Management believes that, based on the current stage of implementation of the new strategic plan, the sources of liquidity and capital resources described above will address our anticipated liquidity, capital expenditures, and other investment requirements.

During the second quarter of 2017, in conjunction with the final approval of the ONGP Portfolio PPA which will require us to make significant capital expenditures in the U.S., the fact that we are currently looking for acquisitions in the U.S, and the acquisition of our Viridity business for a price of $35.3 million with an additional earn-out payment expected to be made in 2021, we have re-evaluated our position with respect to a portion of the unrepatriated earnings of Ormat Systems, our wholly owned subsidiary in Israel, and determined that we can no longer maintain the permanent reinvestment position with respect to a portion of its unrepatriated earnings which will be repatriated to support our capital expenditures in the U.S. Accordingly, and as further described in Note 18 to our consolidated financial statements set forth in Item 8 of this annual report, the permanent reinvestment assertion of foreign unremitted earnings of Ormat Systems was reassessed and removed and the related deferred tax assets and liabilities as well as the estimated withholding taxes on the expected remittance of Ormat Systems earnings to the U.S. were recorded in the second quarter of 2017. The estimated U.S. deferred tax assets and liabilities were adjusted as part of the year-end provision based on changes to U.S. tax law resulting from U.S. tax reform, which is discussed further in Note 18 to our consolidated financial statements set forth in Item 8 of this annual report.

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Although we plan to repatriate undistributed earnings related to Ormat Systems to support expected capital expenditure requirements in the U.S., based upon our plans to increase operations outside of the U.S. it is our intention to reinvest undistributed earnings of its other foreign subsidiaries and thereby indefinitely postpone their remittance given that we require existing and future cash to fund our anticipated investment and development activities as well as debt service requirements in those jurisdictions. In addition, we believe that existing and anticipated cash flows as well as borrowing capacity in the U.S. and cash to be remitted to the U.S. from Ormat Systems will be sufficient to meet our needs in the U.S. If plans change, we may be required to accrue and pay U.S. taxes to repatriate these funds.

Third-Party Debt

Our third-party debt consists of (i) non-recourse and limited-recourse project finance debt or acquisition financing that we or our subsidiaries have obtained for the purpose of developing and constructing, refinancing or acquiring our various projects and (ii) full-recourse debt incurred by us or our subsidiaries for general corporate purposes.

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Non-Recourse and Limited-Recourse Third-Party Debt

OFC Senior Secured Notes — Non-Recourse

In February 2004, our subsidiary Ormat Funding Corp. ("OFC") issued $190.0 million of Senior Secured Notes ("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. Principal and interest on the OFC Senior Secured Notes, which had a final maturity date of December 30, 2020, were payable in semi-annual installment. The OFC Senior Secured Notes were collateralized by substantially all of the assets of OFC and those of its wholly owned subsidiaries and were fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC. In September 2017, the Company fully prepaid the outstanding amount of $14.3 million of OFC Senior Secured Notes, plus an additional make-whole premium of $1.3 million.

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 installments. The OrCal Senior Secured Notes are collateralized by substantially all of the assets of OrCal and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OrCal. There are various restrictive covenants under the OrCal Senior Secured Notes which include limitations on additional indebtedness of OrCal and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OrCal. In addition, there are restrictions on the ability of OrCal to make distributions to its shareholders, which include a required historical and projected 12-month DSCR of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OrCal fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. We are only required to measure these covenants on a semi-annual basis and as of December 31, 2017 (the last measurement date of the covenants) the actual historical 12-month DSCR was 1.54, and the pro-forma 12-months DSCR was 2.63. There was $32.1 million aggregate principal amount of OrCal Senior Secured Notes outstanding as of December 31, 2017.

OFC 2 Senior Secured Notes — Limited Recourse

In September 2011, our subsidiary OFC 2 LLC ("OFC 2") and its wholly owned project subsidiaries (collectively, the "OFC 2 Issuers") entered into a note purchase agreement (the "Note Purchase Agreement") with the OFC 2 Noteholder Trust, as purchaser, John Hancock Life Insurance Company (USA), as administrative agent, and the Department of

Energy (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.

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 are rated “BBB” by Standard and Poor’s. 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, including a historical debt service coverage ratio requirement of at least 1.2 (on a blended basis for all OFC 2 power plants), measured, at the time of any proposed distribution, over each of the two six-month periods comprised of distinct consecutive fiscal quarters immediately preceding the proposed distribution, and a projected future DSCR requirement of at least 1.5 (on a blended basis for all OFC 2 power plants), measured, at the time of any proposed distribution, over each of the two six-month periods comprised of distinct consecutive fiscal quarters immediately following such proposed distribution. As of December 31, 2017, our historical DSCR was 2.70 and 2.25, respectively, for each of the two six-month periods, and our projected future DSCR was 2.04 and 2.13, respectively, for each of the two six-month periods. The OFC 2 Senior Secured Notes mature on December 31, 2034 and the principal amount thereof is payable in equal quarterly installments. Each series of notes will bear interest at a rate calculated based on a spread over the U.S. Treasury yield curve that will be set at least ten business days prior to the issuance of such series of notes. Interest will be payable quarterly in arrears. The DOE guarantees payment of 80% of principal and interest on the OFC 2 Senior Secured Notes pursuant to Section 1705 of Title XVII of the Energy Policy Act of 2005, as amended.

In October 2011, the OFC 2 Issuers completed the sale of $151.7 million aggregate principal amount of 4.687% Series A Notes due 2032 (the “Series A Notes”). The proceeds from the sale of the Series A Notes net of transaction fees and expenses were approximately $141.1 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.

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On June 20, 2014, Phase I of the Tuscarora facility achieved project completion under the Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement, we made a principal payment of $4.3 million on the Series A Notes.

On August 29, 2014, OFC 2 sold $140.0 million principal amount of OFC 2 Senior Secured Notes (the “Series C Notes”) to finance the construction of Phase II of the McGinness Hills project. The Series C Notes, which mature in December 2032, are the last tranche under the Note Purchase Agreement and bear interest at a rate of 4.61%, with principal to be repaid on a quarterly basis.

There were $232.5 million and $247.2 million of OFC 2 Senior Secured Notes outstanding as of December 31, 2017 and December 31, 2016, respectively.

We provided a guarantee in connection with the issuance of the Series A Notes and Series C Notes, which may be drawn upon if any loss, liability, damage, expense or cost to the Jersey Valley facility is incurred as a result of any interconnection related agreements for the Dixie Meadows project that we may develop in the future.

Olkaria III Finance Agreement with OPIC — Limited Recourse

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

The OPIC Loan is comprised of three tranches:

- Tranche I in an aggregate principal amount of $85.0 million, which matures on December 15, 2030 and bears interest at a fixed rate of 6.34%, was drawn in November 2012 and 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 Third Party Debt”. The remainder of the Tranche I proceeds were used for reimbursement of prior capital expenditures and other corporate purposes. As of December 31, 2017, Tranche I had an outstanding balance of $61.4 million.
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Tranche II in an aggregate principal amount of $180.0 million, which matures on June 15, 2030 and bears interest at a fixed rate of 6.29%, was used to fund the construction and well field drilling for Plant 2 of the Olkaria III complex. In November 2012 and February 2013, $135.0 million and the remaining $45.0 million, respectively, was drawn under this Tranche II. As of December 31, 2017, Tranche II had an outstanding balance of $132.4 million.

- Tranche III in an aggregate principal amount of $45.0 million, which matures on December 15, 2030 and bears interest at a fixed rate of 6.12%, was used to fund the construction of Plant 3 of the Olkaria III complex and was drawn down in full in November 2013. As of December 31, 2017, Tranche III had an outstanding balance of $34.9 million.

OrPower 4 may voluntarily prepay all or a portion of the OPIC Loan, subject to prior notice, minimum prepayment amounts, and a prepayment premium of 2% 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 in the Olkaria III complex, 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.

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 became effective on December 15, 2014. As of December 31, 2017, the actual historical and projected 12-month DSCR was 2.64 and 3.09, respectively.

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As of December 31, 2017, $228.6 million of the OPIC Loan was outstanding.

Amatitlan Financing — Limited Recourse

On July 31, 2015, one of our indirect wholly-owned subsidiaries, Ortitl n, Limitada, obtained a 12-year secured term loan in the principal amount of $42.0 million for the 20 MW Amatitlan power plant in Guatemala. Under the credit agreement with Banco Industrial S.A. and Westrust Bank (International) Limited, we can expand the Amatitlan power plant with financing to be provided either via equity, additional debt from Banco Industrial S.A. or from other lenders, subject to certain limitations on expansion financing in the credit agreement.

The loan is payable in 48 quarterly payments commencing September 30, 2015. The loan bears interest at a rate *per annum* equal to the sum of the LIBO Rate (which cannot be lower than 1.25%) plus a margin of (i) 4.35% as long as the Company’s guaranty of the loan (as described below) is outstanding or (ii) 4.75% otherwise. Interest is payable quarterly, on March 30, June 30, September 30 and December 30 of each year, on the stated maturity date of the loan and on any prepayment or payment of the loan. The loan must be prepaid upon the occurrence of certain events, such as casualty, condemnation, asset sales and expansion financing not provided by the lenders under the credit agreement, among others. The loan may be voluntarily prepaid if certain conditions are satisfied, including payment of a premium (ranging from 100-50 basis points) if prepayment occurs prior to the eighth anniversary of the loan.

There are various restrictive covenants under the Amatitlan credit agreement. These include, among others, (i) a financial covenant to maintain a Debt Service Coverage Ratio (as defined in the credit agreement) of not less than 1.15 to 1.00 as of the last day of any fiscal quarter and (ii) limitations on Restricted Payments (as defined in the credit agreement) that among other things would limit dividends that could be paid to us unless the historical and projected Debt Service Coverage Ratio is not less than 1.25 to 1.00 for the four fiscal quarterly periods (calculated as a single accounting period). As of December 31, 2017, the actual historical and projected 12-month Debt Service Coverage Ratio was 1.49 and 1.89, respectively. The credit agreement includes various events of default that would permit acceleration of the loan (subject in some cases to grace and cure periods). These include, among others, a Change of Control (as defined in the credit agreement) and failure to maintain certain required balances in debt service and maintenance reserve accounts. The credit agreement includes certain equity cure rights for failure to maintain the Debt Service Coverage Ratio and the minimum amounts required in the debt service and maintenance reserve accounts.

The loan is secured by substantially all the assets of the borrower and a pledge of all of the membership interests of the borrower.

The Company has guaranteed payment of all obligations under the credit agreement and related financing documents. The guaranty is limited in the sense that the Company is only required to pay the guaranteed obligations if a “trigger event” occurs. A trigger event is the occurrence and continuation of a default by INDE in its payment obligations under the PPA for the Amatitlàn power plant or a refusal by INDE to receive capacity and energy sold under that PPA. Our obligations under the guaranty may be terminated prior to payment in full of the guaranteed obligations under certain circumstances described in the guaranty. If our guaranty is terminated early, the interest rate payable on the loan would increase as described above.

As of December 31, 2017, $33.3 million of this loan is outstanding.

Don A. Campbell Senior Secured Notes — Non-Recourse

On November 29, 2016, ORNI 47 LLC (“ORNI 47”) entered into a note purchase agreement (the “ORNI 47 Note Purchase Agreement”) with MUFG Union Bank, N.A., as collateral agent, Munich Reinsurance America, Inc. and Munich American Reassurance Company (the “Purchasers”) pursuant to which ORNI 47 issued and sold to the Purchasers $92.5 million aggregate principal amount of its 4.03% Senior Secured Notes due September 27, 2033 (the “DAC 1 Senior Secured Notes”) in a private placement exempt from the registration requirements of the Securities Act of 1933, as amended. ORNI 47 is the owner of phase I of the Don A. Campbell (“DAC 1”) geothermal power plant.

The net proceeds to ORNI 47 from the sale of the DAC 1 Senior Secured Notes, after deducting certain transaction expenses and the funding of a debt service reserve account, were approximately $87.1 million. ORNI 47 intends to use the proceeds from the sale of the DAC 1 Senior Secured Notes to refinance the development and construction costs of the DAC 1 geothermal power plant, which were originally financed using equity.

ORNI 47 began paying a scheduled amount of principal of the DAC 1 Senior Secured Notes on December 27, 2016 and now makes principal payments quarterly, on the 27th day of each of March, June, September and December, until maturity.

The DAC 1 Senior Secured Notes constitute senior secured obligations of ORNI 47 and are secured by all of the assets of ORNI 47. Under the ORNI 47 Note Purchase Agreement, ORNI 47 may prepay at any time all, or from time to time any part of, the DAC 1 Senior Secured Notes in an amount equal to at least $2 million or such lesser amount as may remain outstanding under the DAC 1 Senior Secured Notes at 100% of the principal amount to be prepaid plus the applicable make-whole amount determined for the prepayment date with respect to such principal amount. Upon the occurrence of a Change of Control (as defined in the ORNI 47 Note Purchase Agreement), ORNI 47 must make an offer to each holder of DAC 1 Senior Secured Notes to repurchase all of the holder's DAC 1 Senior Secured Notes at 101% of the aggregate principal amount of DAC 1 Senior Secured Notes to be repurchased plus accrued and unpaid interest, if any, on the DAC 1 Senior Secured Notes to be repurchased, but not including, the date of repurchase. Each holder of DAC 1 Senior Secured Notes may accept such offer in whole or in part. In certain events, including certain asset sales outside the ordinary course of business, ORNI 47 must make mandatory prepayments of the DAC 1 Senior Secured Notes at 100% of the principal amount to be prepaid. The ORNI 47 Note Purchase Agreement requires ORNI 47 to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens, amendment or modification of material project documents, the ability of ORNI 47 to merge or consolidate with another entity. The ORNI 47 Note Purchase Agreement also contains customary events of default. In addition, there are restrictions on the ability of ORNI 47 to make distributions to its shareholders, which include a required historical and projected DSCR not less than 1.20 for the four fiscal quarterly periods. As of December 31, 2017, the historical and projected DSCR were 1.47 and 1.81, respectively.

As of December 31, 2017, $88.3 million of DAC 1 Senior Secured Notes is outstanding.

Full-Recourse Third-Party Debt

Credit Agreements

Union Bank. In February 2012, Ormat Nevada, our wholly owned subsidiary, entered into an amended and restated credit agreement with Union Bank. Under the credit agreement the credit termination date is June 30, 2018. On

December 31, 2016, the aggregate amount available under the credit agreement was increased by $10 million to $60.0 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 lenders. 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 for Ormat Nevada 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 December 31, 2017: (i) the actual 12-month debt to EBITDA ratio was 2.17; (ii) the 12-month DSCR was 2.96; and (iii) the distribution leverage ratio was 0.99. 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 December 31, 2017, letters of credit in the aggregate amount of $37.4 million remained issued and outstanding under this committed credit agreement with Union Bank.

HSBC. In May 2013, Ormat Nevada entered into a credit agreement with HSBC Bank USA, N.A for one year with annual renewals. The current expiration date of the credit facility is August 31, 2018. The aggregate amount available under the credit agreement was increased by $10 million to $35.0 million. Other than $10.0 million of this credit facility which may be drawn for our working capital needs, this credit facility is limited to the issuance, extension, modification or amendment of letters of credit. 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 lenders. 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.

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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 December 31, 2017: (i) the actual 12-month debt to EBITDA ratio was 2.17; (ii) the 12-month DSCR was 2.96; and (iii) the distribution leverage ratio was 0.99. 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 December 31, 2017, letters of credit in the aggregate amount of $16.2 million remain issued and outstanding under this committed credit agreement.

CHUBB Surety Bond. In May 2017, the Company entered into a surety bond agreement (the "Surety Agreement") with Chubb Limited ("Chubb") pursuant to which the Company may request that Chubb issue up to an aggregate $200.0 million of surety bonds with respect to the contractual obligations of the Company and its subsidiaries in exchange for bank letters of credit or as otherwise may be required. There is no expiration date for the Surety Agreement, but it may be terminated by the Company at any time upon twenty days' prior written notice to Chubb. Delivery of such termination notice will not affect any surety bonds issued and outstanding prior to the date on which such notice is delivered. As of December 31, 2017, Chubb issued a surety bond in the amount of $106.2 million under the Surety Agreement, primarily in in respect of the Company's obligations under the PPA with SCPPA.

Other Banks. We also have committed credit agreements with five other commercial banks for an aggregate amount of $373.0 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 $233.0 million; and (ii) the issuance of one or more letters of credit in the amount of up to $140.0 million. The credit agreements mature at the end of March 2018 and July 2019. We are currently negotiating the extension of the credit agreements maturing in March 2018. 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 December 31, 2017, $51.5 million was outstanding under these credit agreements.

As of December 31, 2017, letters of credit with an aggregate stated amount of $224.1 million were issued and outstanding under these credit agreements.

Letters of Credits under the Credit Agreements

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

As of December 31, 2017, committed letters of credit in the aggregate amount of $277.7 million remained issued and outstanding under the credit agreements with Union Bank, HSBC and five of the commercial banks as described under “Credit Agreements”.

Term Loans. We had a $20.0 million term loan with a group of institutional investors which matured on August 1, 2017. The loan was payable in 12 semi-annual installments commencing February 1, 2012 and bore interest at 6-month LIBOR plus 5.0%. On August 1, 2017, the loan was fully paid.

Senior Unsecured Bonds. We issued approximately $142.0 million aggregate principal amount of senior unsecured bonds in August 2010 and an additional $107.5 million aggregate principal amount of senior unsecured bonds in February 2011. Subject to early redemption, the principal of the bonds was repayable in a single bullet payment upon the final maturity of the bonds on August 1, 2017. The bonds bore 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 reflected an effective fixed interest rate of 6.75%.

On September 8, 2016, we concluded an auction tender and accepted subscriptions for $204 million aggregate principal amount of two tranches of senior unsecured bonds comprised of approximately $67 million aggregate principal amount of Series 2 Bonds (the “Series 2 Bonds”) and approximately $137 million aggregate principal amount of Series 3 Bonds (the “Series 3 Bonds”). The proceeds from the Series 2 Bonds and Series 3 Bonds were used on September 29, 2016, to prepay our $250 million senior secured bonds that were payable on August 1, 2017 described above.

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The Series 2 Bonds will mature in September 2020 and bear interest at a fixed rate of 3.7% per annum, payable semi-annually. The Series 3 Bonds will mature in September 2022 and bear interest at a fixed rate of 4.45% per annum, payable semi-annually. The Series 2 Bonds and Series 3 Bonds will be repaid at maturity in a single bullet payment, unless earlier prepaid pursuant to the terms and conditions of the trust instrument that governs such bonds. Both tranches received a rating of ilA+ from Maloot S&P in Israel with a stable outlook.

Loan Agreements with DEG (the Olkaria III Complex). OrPower 4 entered into a project financing loan (the "DEG 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 DEG. The DEG Loan will mature on December 15, 2018 and is payable in 19 equal semi-annual installments. Interest on the loan was variable based on 6-month LIBOR plus 4.0%. We fixed the interest rate on most of the loan at 6.90%. In September 2017, we fully prepaid the outstanding amount of $11.8 million of the DEG Loan, plus an additional prepayment fee of $0.1 million.

On October 20, 2016, OrPower 4 entered into a new $50 million subordinated loan agreement with DEG (the "DEG 2 Loan Agreement") and on December 21, 2016, OrPower 4 completed a drawdown of the full loan commitment amount of $50 million, which bears interest at a fixed rate of 6.28% for the duration of the loan (the "DEG 2 Loan"). The DEG 2 Loan, which matures on June 21, 2028, will be repaid in 20 equal semi-annual principal installments commencing December 21, 2018. Proceeds of the DEG 2 Loan were used by Orpower 4 to refinance Plant 4 of the Olkaria III Complex, which was originally financed using equity. The DEG 2 Loan is subordinated to the senior loan provided by OPIC for Plants 1-3 of the Olkaria III complex. The DEG 2 Loan is guaranteed by the Company.

Under the DEG 2 Loan Agreement, OrPower 4 may prepay at any time all, or from time to time any part of the DEG 2 Loan in an amount equal to at least $5 million or such lesser amount as may remain outstanding under the DEG 2 Loan at 100% of the principal amount to be prepaid plus the applicable make-whole amount and certain prepayment premium amount determined for the prepayment date with respect to such principal amount. In certain events, OrPower 4 must make mandatory prepayments of the DEG 2 Loan at 100% of the principal amount to be prepaid plus the applicable make-whole amount and certain prepayment premium amount determined for the prepayment date with respect to such principal amount. The DEG 2 Loan Agreement requires OrPower 4 to comply with certain covenants, including, among others, restrictions on the incurrence of indebtedness or liens. The DEG 2 Loan Agreement also contains customary events of default.

As of December 31, 2017, $50.0 million is outstanding under the DEG 2 Loan.

Restrictive covenants

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 25% of total assets; (ii) 12-month debt, net of cash, cash equivalents, and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6.0; and (iii) dividend distributions not to exceed 35% of net income in any calendar year. As of December 31, 2017: (i) total equity was $1,295.7 million and the actual equity to total assets ratio was 49.4% and (ii) the 12-month debt, net of cash, cash equivalents, to Adjusted EBITDA ratio was 2.6. During the year ended December 31, 2017, we distributed interim dividends in an aggregate amount of $20.5 million. 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.

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Future minimum payments

Future minimum payments under long-term obligations, excluding revolving credit lines with commercial banks and lease payments under the Puna lease transaction described below, as of December 31, 2017, are as follows:

	(Dollars in thousands)
Year ending December 31:	
2018	$ 57,807
2019	55,539
2020	123,093
2021	46,579
2022	184,148
Thereafter	409,898
Total	$ 877,064

Puna Power Plant Lease Transactions

In May 2005, our Hawaiian subsidiary, PGV, entered into a transaction involving the original geothermal power plant of the Puna complex located on the Big Island (the Puna Power Plant).

Pursuant to a 31-year head lease (the Head Lease), PGV leased the Puna Power Plant to an unrelated lessor (the Puna lessor) in return for prepaid lease payments in the total amount of $83.0 million. The carrying value of the leased assets as of December 31, 2017 amounted to $25.3 million, net of accumulated depreciation of $35.6 million. The Puna Lessor simultaneously leased back the Puna Power Plant to PGV under a 23-year lease (the Project Lease). PGV’s rent obligations under the Project Lease will be paid solely from revenues generated by the Puna Power Plant under a PPA that PGV has with HELCO. The Head Lease and the Project Lease are non-recourse lease obligations to the Company. PGV’s rights in the geothermal resource and the related PPA have not been leased to the Puna Lessor as part of the Head Lease but are part of the Puna Lessor’s security package.

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.

There are various restrictive covenants under the lease agreement, including a requirement to have certain reserve funds that need to be managed by the indenture trustee in accordance with certain balance requirements. Such reserve funds amounted to $7.9 million and $2.9 million as of December 31, 2017 and December 31, 2016, respectively, and were included in restricted cash accounts in the consolidated balance sheets and were classified as current as they were used for current payments.

Opal Geo Transaction

On December 16, 2016, Ormat Nevada entered into an equity contribution agreement (the “Equity Contribution Agreement”) with OrLeaf LLC (“OrLeaf”) and JPM Capital Corporation (“JPM”) with respect to Opal Geo. Also on December 16, 2016, OrLeaf, a newly formed limited liability company formed by Ormat Nevada and ORPD LLC, entered into an amended and restated limited liability company agreement of Opal Geo (the “LLC Agreement”) with JPM. The transactions contemplated by the Equity Contribution Agreement and LLC Agreement will allow the Company to monetize federal production tax credits (“PTCs”) and certain other tax benefits relating to the operation of five geothermal power plants located in Nevada.

In connection with the transactions contemplated by the Equity Contribution Agreement and the LLC Agreement, Ormat Nevada transferred its indirect ownership interest in the McGinness Hills (Phase I and Phase II), Tuscarora, Jersey Valley and phase 2 of the Don A. Campbell ("DAC 2") geothermal power plants to Opal Geo. Prior to such transfer, Ormat Nevada held an approximately 63.25% indirect ownership interest in DAC 2 through ORPD LLC, a joint venture between Ormat Nevada and Northleaf Geothermal Holdings LLC ("Northleaf"), an affiliate of Northleaf Capital Partners, and held, directly or indirectly, a 100% ownership interest in the remaining geothermal power plants that were transferred to Opal Geo.

Pursuant to the Equity Contribution Agreement, JPM contributed approximately $62.1 million to Opal Geo in exchange for 100% of the Class B Membership Interests of Opal Geo. JPM also agreed to make deferred capital contributions to Opal Geo based on the amount of electricity generated by the DAC 2 and McGinness Hills Phase II power plants which are eligible for the federal PTC. We expect the aggregate amount of JPM's deferred capital contributions to equal approximately $21 million and to be paid over time covering the period through December 31, 2022.

Under the LLC Agreement, until December 31, 2022, OrLeaf will receive distributions of 97.5% of any distributable cash generated by operation of the power plants while JPM will receive distributions of 2.5% of any distributable cash generated by operation of the power plants. Unless JPM has already achieved its target internal rate of return on its investment in Opal Geo, from December 31, 2022 until JPM has achieved its target internal rate of return, JPM will receive 100% of any distributable cash generated by operation of the power plants. Thereafter, OrLeaf will receive distributions of 97.5%, and JPM will receive 2.5%, of any distributable cash generated by operation of the power plants.

Under the LLC Agreement, all items of Opal Geo income and loss, gain, deduction and credit (including the federal PTCs relating to the operation of the two PTC eligible power plants) will be allocated, until JPM has achieved its target internal rate of return on its investment in Opal Geo (and for so long as the two PTC eligible power plants are generating PTCs), 99% to JPM and 1% to OrLeaf, or 5% to JPM and 95% to OrLeaf if PTCs are no longer available to either of the two PTC eligible power plants. Once JPM achieves its target internal rate of return, all items of Opal Geo income and loss, gain, deduction and credit will be allocated 5% to JPM and 95% to OrLeaf.

Under the LLC Agreement, OrLeaf, which owns 100% of the Class A Membership Interests in Opal Geo, will serve as the managing member of Opal Geo and control the day-to-day management of Opal Geo and its portfolio of five power plants. However, in certain limited circumstances (such as bankruptcy of Orleaf, fraud or gross negligence by OrLeaf) JPM may remove OrLeaf as the managing member of Opal Geo. JPM, as the Class B Member of Opal Geo, has consent and approval rights with respect to certain items that are designated as major decisions for Opal Geo and the five power plants. In addition, by virtue of certain provisions in OrLeaf's own limited liability company agreement, and consistent with the ORPD formation documents, Northleaf has similar consent and approval rights with respect to OrLeaf's determination of major decisions pertaining to the DAC 2 power plant. In both cases, these major decisions are generally equivalent to customary minority protection rights. As a result, the Company's wholly owned subsidiary, Ormat Nevada, which serves as the managing member of OrLeaf and as the managing member of ORPD, will effectively retain the day-to-day control and management of Opal Geo and its portfolio of five power plants.

The LLC Agreement contains certain customary restrictions on transfer applicable to both OrLeaf and JPM with respect to their respective membership interests in Opal Geo, and also provides OrLeaf with a right of first offer in the event JPM desires to transfer any of its Class B Membership Interests, pursuant to which OrLeaf may purchase such Class B Membership Interests. The LLC Agreement also provides OrLeaf with the option to purchase all of the Class B Membership Interests on either December 31, 2022 or the date that is 9 years after the closing date under the Equity Contribution Agreement at a price equal to the greater of (i) the fair market value of the Class B Membership Interests as of the date of purchase (subject to certain adjustments) and (ii) $3 million.

Pursuant to the Equity Contribution Agreement, the Company has provided a guaranty for the benefit of JPM of certain of OrLeaf's indemnification obligations to JPM under the LLC Agreement. In addition, Ormat Nevada also provided a guaranty for the benefit of JPM of all present and future payment and performance obligations of OrLeaf under the LLC Agreement and each ancillary document to which OrLeaf is a party.

JPM's $62.1 million capital contribution to Opal Geo was recorded as a $3.7 million allocation to noncontrolling interests and a $58.5 million allocation to Liabilities associated with sale of tax benefits as described in Note 1 to our consolidated financial statements set forth in Item 8 of this annual report.

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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 continued 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 received both the distributable cash flow and the Economic Benefits. Once the investors reached a target after-tax yield on their investment in OPC (the OPC Flip Date), Ormat Nevada received 95% of both distributable cash and taxable income, on a going forward basis.

The Class B membership units have a 5% residual economic interest in OPC, which commenced as of the OPC Flip Date. This residual 5% interest represented a noncontrolling interest and is not subject to mandatory redemption or guaranteed payments. As detailed under Note 13 to our consolidated financial statements set forth in Item 8 of this annual report, the OPC Flip Date occurred on May 31, 2017 and Ormat Nevada purchased all of the Class B membership units from JP Morgan and Morgan Stanley on October 31, 2017 for $1.9 million. As a result, Ormat Nevada is now the sole owner of all the economic and voting interests in OPC and continues to consolidate OPC in its financial statements.

ORTP Transaction

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

Under the terms of the transaction, Ormat Nevada transferred the Heber complex, the Mammoth complex, the Ormesa complex, and the Steamboat 2 and 3, Burdette (Galena 1) and Brady power plants to ORTP, and sold Class B membership units in ORTP to JPM. In connection with the closing, JPM paid approximately $35.7 million to Ormat Nevada and made additional payments to Ormat Nevada of 25% of the value of PTCs generated by the portfolio over time.

Ormat Nevada continued 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 JPM will received substantially all the Economic Benefits. JPM's return was limited by the terms of the transaction. Once JPM reached a target after-tax yield on its investment in ORTP (the ORTP Flip Date), Ormat Nevada received 97.5% of the distributable cash and 95.0% of the taxable income, on a going forward basis. At any time during the twelve-month period after the end of the fiscal year in which the ORTP Flip Date occurs (but no earlier than the expiration of five years following the date that the last of the power plants was placed in service for purposes of federal income taxes), Ormat Nevada had the option to purchase JPM's remaining interest in ORTP at the then-current fair market value. As detailed under Note 13 to our consolidated financial statements set forth in Item 8 of this annual report, the ORTP Flip Date occurred on March 30, 2017 and Ormat Nevada purchased all of the Class B membership units from JP Morgan as discussed below.

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The Class B membership units entitled 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, which occurred on March 30, 2017. On July 10, 2017, Ormat Nevada purchased all of the Class B membership interests in ORTP from JPM for $2.4 million. As a result, Ormat Nevada is now the sole owner of all economic and voting interests in ORTP and we continue to consolidate ORTP in our consolidated financial statements.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 19 to our consolidated financial statements set forth in Item 8 of this annual 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 December 31, 2017. This liability is included in long-term liabilities in our 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.

Dividend

The following are the dividends declared by us during the past two years:

Date Declared	**Dividend Amount per Share**	**Record Date**	**Payment Date**
February 23, 2016	$ 0.31	March 15, 2016	March 29, 2016
May 4, 2016	$ 0.07	May 18, 2016	May 24, 2016
August 2, 2016	$ 0.07	August 16, 2016	August 30, 2016
November 7, 2016	$ 0.07	November 21, 2016	December 6, 2016
February 28, 2017	$ 0.17	March 15, 2017	March 29, 2017
May 8, 2017	$ 0.08	May 22, 2017	May 31, 2017
August 3, 2017	$ 0.08	August 15, 2017	August 29, 2017
November 7, 2017	$ 0.08	November 21, 2017	December 5, 2017
March 1, 2018	$ 0.23	March 14, 2018	March 29, 2018

Historical Cash Flows

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

	Year Ended December 31,		
	2017	2016	2015
	(Dollars in thousands)		
Net cash provided by operating activities	$245,575	$159,285	$190,025
Net cash used in investing activities	(368,121)	(158,531)	(90,971)
Net cash provided by (used in) financing activities	(59,850)	43,541	46,635
Net change in cash and cash equivalents	(182,396)	44,295	145,689

For the Year Ended December 31, 2017

Net cash provided by operating activities for the year ended December 31, 2017 was $245.6 million, compared to $159.3 million for the year ended December 31, 2016. This increase of $86.3 million resulted primarily from (i) an increase in receivables of $24.0 million in the year ended December 31, 2017, compared to $33.3 million in the year ended December 31, 2016, as a result of timing of collections from our customers; and (ii) a decrease in billing in excess of costs and estimated earnings on uncompleted contracts, net of $0.1 million in our Product segment in the year ended December 31, 2017, compared to $29.3 million in the year ended December 31, 2016, as a result of timing in billing of our customers; and (iii) an increase in accounts payable and accrued expenses of $51.6 million in the year ended December 31, 2017, compared to a decrease of $1.4 million in the year ended December 31, 2016, as a result of timing of payments to our suppliers.

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Net cash used in investing activities for the year ended December 31, 2017 was $368.1 million, compared to $158.5 million for the year ended December 31, 2016. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2017 were: (i) capital expenditures of $259.2 million, primarily for our facilities under construction; (ii) $35.3 million net cash paid for the acquisition of our Viridity business; (iii) a net increase of $14.6 million in restricted cash and cash equivalents, due to timing of debt repayments; and (iv) an investment in an unconsolidated company of $46.3 million.

Net cash used in financing activities for the year ended December 31, 2017 was $59.9 million, compared to $43.5 million provided by for the year ended December 31, 2016. The principal factors that affected the net cash used in financing activities during the year ended December 31, 2017 were: (i) the repayment of long-term debt in the amount of $66.2 million; (ii) a $20.5 million cash dividend paid; (iii) $21.3 million of cash paid to noncontrolling interests; (iv) $14.3 million of cash paid to repurchase our OFC Senior Secured Notes, partially offset by a net increase of $51.5 million against our revolving lines of credit with commercial banks.

For the Year Ended December 31, 2016

Net cash provided by operating activities for the year ended December 31, 2016 was $159.3 million, compared to $190.0 million for the year ended December 31, 2015. This decrease of $30.7 million resulted primarily from (i) an increase in receivables of $33.3 million in the year ended December 31, 2016, compared to $3.8 million in the year ended December 31, 2015, as a result of timing of collections from our customers; and (ii) a decrease in billing in excess of costs and estimated earnings on uncompleted contracts, net of $29.3 million in our Product segment in the year ended December 31, 2016, compared to an increase of $11.8 million in the year ended December 31, 2015, as a result of timing in billing of our customers.

Net cash used in investing activities for the year ended December 31, 2016 was $158.5 million, compared to $91.0 million for the year ended December 31, 2015. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2016 were capital expenditures of $151.9 million, primarily for our facilities under construction, and $20.1 million net cash paid for the acquisition of GB, reduced by a net decrease of $15.2 million in restricted cash and cash equivalents, due to timing of debt repayments.

Net cash provided by financing activities for the year ended December 31, 2016 was $43.5 million, compared to $46.6 million used for the year ended December 31, 2015. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2016 were: (i) $203.5 million net proceeds from issuance of two new series of Senior Unsecured Bonds; (ii) net proceeds from issuance of shares to a noncontrolling interest in the amount of $44.1 million; (iii) $59.9 million of net proceed from the Opal Geo transaction; (iv) $92.5 million of proceeds from a term loan for our Don A. Campbell power plant and (v) $50.0 million of proceeds from a term loan for our Olkaria 3 Complex plant 4, reduced by: (i) early repayment of $249.5 million of Senior Unsecured Bonds; $6.8 million of cash paid to repurchase our OFC Senior Secured Notes; (ii) the repayment of long-term debt in the amount of $62.1 million; (iii) $63.7 million of cash paid to noncontrolling interests; and (iv) a $26.0 million cash dividend paid.

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, adjusted for (i) termination fees, (ii) impairment of long-lived assets, (iii) write-off of unsuccessful exploration activities, (iv) any mark-to-market gains or losses from accounting for derivatives, (v) merger and acquisition transaction costs (vi) stock-based compensation, (vii) gain or loss from extinguishment of liabilities (viii) gain or loss on sale of subsidiary and property, plant and equipment and (ix) other unusual or non-recurring items. EBITDA and Adjusted EBITDA are not measurements of financial performance or liquidity under accounting principles generally accepted in the U.S., or U.S. GAAP, and should not be considered as an alternative to cash flow from operating activities or as a measure of liquidity or an alternative to net earnings as indicators of our operating performance or any other measures of performance derived in accordance with U.S. 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.

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This information should not be considered in isolation from, 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 year ended December 31, 2017 was $343.8 million, compared to $323.8 million for the year ended December 31, 2016 and $291.3 million for the year ended December 31, 2015.

The following table reconciles net cash provided by operating activities to EBITDA and adjusted EBITDA, for the years ended December 31, 2017, 2016, and 2015:

	Year Ended December 31,		
	2017 (As restated)	2016	2015
	(in thousands)		
Net cash provided by operating activities	$245,575	$159,285	$190,025
Adjusted for:			
Interest expense, net (excluding amortization of deferred financing costs)	47,689	60,553	63,802
Interest income	(988)	(971)	(297)
Income tax provision (benefit)	21,664	37,059	(16,057)
Adjustment to investment in an unconsolidated company: our proportionate share in interest expense, tax and depreciation and amortization in Sarulla	(265)	-	-
Adjustments to reconcile net income to net cash provided by operating activities (excluding depreciation and amortization)	16,680	42,986	41,329
EBITDA	330,355	298,912	278,802
Mark-to-market on derivative instruments	(1,500)	319	1,409
Stock-based compensation	8,760	5,157	3,955
Gain on sale of subsidiary and property, plant and equipment	-	(686)	-
Termination fee	-	-	-
Impairment of long-lived assets	-	-	-
Loss from extinguishment of liability	1,950	5,780	1,710
Merger and acquisition transaction costs	2,460	335	3,800
Settlement expenses	-	11,000	-
Write-off of unsuccessful exploration activities	1,796	3,017	1,579
Adjusted EBITDA	$343,821	$323,834	$291,255
Net cash used in investing activities	$(368,121)	$(158,531)	$(90,971)
Net cash used in (provided by) financing activities	$(59,850)	$43,541	$46,635

EBITDA includes the proportionate share (12.75%) of net depreciation, interest and tax expenses from our unconsolidated investment in the Sarulla project that is accounted for under the equity method.

On May 2014, the Sarulla consortium (“SOL”) closed $1,170 million in financing. As of December 31, 2017, the credit facility has an outstanding balance of $1,042.7 million. Our proportionate share in SOL credit facility is $132.9 million.

Capital Expenditures

Our capital expenditures primarily relate to the enhancement of our existing power plants and the exploration, development and construction of new power plants.

We have budgeted approximately $366.0 million in capital expenditures for construction of new projects and enhancements to our existing power plants, of which we have invested approximately $142.0 million as of December 31, 2017. We expect to invest $156.0 million in 2018 and the remaining $68.0 million thereafter.

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In addition, we estimate approximately $144.0 million in additional capital expenditures in 2018 to be allocated as follows: (i) $21.0 million for development of new projects; (ii) $51.0 million for maintenance of capital expenditures to our operating power plants including $18 million investment for stand by wells that we plan to drill at our Puna power plant; (iii) $20.0 million for continued exploration activity under various leases for geothermal resources where we have already started exploration activity; (iv) $40 million for the construction and development of storage projects; and (v) $12.0 million for enhancements to our production facilities.

In the aggregate, we estimate our total capital expenditures for 2018 to be approximately $300.0 million.

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.

Exposure to Market Risks

We, like other power plant operators, are exposed to electricity price volatility risk. 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 aggregate of between 30 MW and 40 MW PPAs for the Heber 2 power plant in the Heber 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. The energy payments under the PPAs of the Heber 2 power plant in the Heber 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, or by reducing the price of purchasing its electrical energy needs from natural gas power plants, which in turn will reduce the energy payments that we may charge under the relevant PPA for these power plants. 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 HELCO's avoided costs.

As of December 31, 2017, 95.4% of our consolidated long-term debt was fixed rate debt and therefore was not subject to interest rate volatility risk and 4.6% of our long-term debt was floating rate debt, exposing us to interest rate risk in connection therewith. As of December 31, 2017, $40.5 million of our long-term debt remained subject to some interest rate risk.

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

Our cash equivalents are subject to interest rate risk. Fixed rate securities may have their market value adversely impacted by a rise in interest rates, while floating rate securities may produce less income than expected if interest rates fall. As a result of these factors, our future investment income may fall short of expectations because of changes in interest rates, or we may suffer losses in principal if we are forced to sell securities that decline in market value because of changes in interest rates.

We are also exposed to foreign currency exchange risk, 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 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.

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We performed a sensitivity analysis on the fair values of our long-term debt obligations and foreign currency exchange forward contracts. The foreign currency exchange forward contracts listed below principally relate to trading activities. The sensitivity analysis involved increasing and decreasing forward rates at December 31, 2017 and 2016 by a hypothetical 10% and calculating the resulting change in the fair values.

At this time, the development of our new strategic plan has not exposed us to any additional market risk. However, as the implementation of the plan progresses, we may be exposed to additional or different market risks.

The results of the sensitivity analysis calculations as of December 31, 2017 and 2016 are presented below:

	Assuming a 10% Increase in Rates		**Assuming a 10% Decrease in Rates**		
	As of December 31,		**As of December 31,**		
Risk	**2017**	**2016**	**2017**	**2016**	**Change in the Fair Value of**
	(In thousands)				
Foreign Currency	$(5,181)	$(4,665)	$6,332	$4,632	Foreign Currency Forward Contracts
Interest Rate	$-	$(254)	$-	$260	OFC Senior Secured Notes
Interest Rate	$(193)	$(281)	$195	$284	OrCal Senior Secured Notes
Interest Rate	$(6,393)	$(7,174)	$6,662	$7,496	OFC 2 Senior Secured Notes
Interest Rate	$-	$(64)	$-	$65	DEG Loan
Interest Rate	$(6,710)	$(7,667)	$7,015	$8,039	OPIC Loan
Interest Rate	$-(1)	$-(1)	$-(1)	$-(1)	Amatitlan loan
Interest Rate	$(3,678)	$(4,351)	$3,766	$4,472	Senior Unsecured Bonds
Interest Rate	$(1,384)	$(1,568)	$1,442	$1,639	DEG 2 Loan
Interest Rate	$(2,476)	$(2,749)	$2,596	$2,890	DAC 1 Senior Secured Notes
Interest Rate	$(171)	$(161)	$177	$167	Other long-term loans

(1) The application of a 10% increase and/or decrease to the interest rate did not exceed the minimum rate as set forth in the loan agreement.

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 provisions that mitigate inflation risk.

In connection with the Electricity segment, none of our U.S. PPAs, including the SCPPA Portfolio PPA, are directly linked to the CPI. Inflation may directly impact an expense we incur for the operation of our projects, thereby increasing our overall operating costs and reduce our profit and gross margin. 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 our PPAs for some of our power plants such as the Brady power plant, the Steamboat 2 and 3 power plants and the McGinness complex, 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 calculated 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, thereby increasing our operating costs in the Product segment. We are more likely to be able to offset all or part of this inflationary impact through our project pricing. With respect to power plants that we build 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.

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Contractual Obligations and Commercial Commitments

The following tables set forth our material contractual obligations as of December 31, 2017 (in thousands):

	Payments Due By Period						
	Remaining Total	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Long-term liabilities principal	$877,064	$57,807	$55,539	$123,093	$46,579	$184,148	$ 409,898
Interest on long-term liabilities (1)	276,540	44,193	40,198	37,094	31,598	29,054	94,403
Future minimum operating lease	26,249	13,317	6,018	2,450	1,723	824	1,917
Benefits upon retirement (2)	15,171	4,258	1,803	1,242	1,418	2,112	4,338
Asset retirement obligation	27,110	—	—	—	—	—	27,110
Purchase commitments (3)	113,406	113,406	—	—	—	—	—
	$1,335,540	$232,981	$103,558	$163,879	$81,318	$216,138	$ 537,666

(1) Interest on the OrCal Senior Secured Notes due in 2020 is fixed at a rate of 6.21%. Interest on the OFC 2 Senior Secured Notes Series A due in 2032 is fixed at a rate of 4.687%. Interest on the DAC 1 Senior Secured Notes due in 2033 is fixed at a rate of 4.03%. Interest on the OPIC Loan due in 2030 is fixed at an average rate of 6.29%. Interest on the DEG 2 Loan due in 2028 is fixed at a rate of 6.28%. Interest on the Senior Unsecured Bonds due in 2020 is fixed at a rate of 3.7%. Interest on the Senior Unsecured Bonds due in 2022 is fixed at a rate of 4.45%. Interest on the remaining debt is variable (based primarily on changes in LIBOR rates). For purposes of the above calculation of interest payments pertaining to variable rate debt, future LIBOR rates were based on constant maturity swaps.

(2) The above amounts were determined based on the employees' current salary rates and the number of years' service that will have been accumulated at their expected retirement date. These amounts do not include amounts that might be paid to employees that will cease working with us before reaching their expected retirement age.

(3) We purchase raw materials for inventories, construction-in-process and services from a variety of vendors. During the normal course of business, in order to manage manufacturing lead times and help assure adequate supply, we enter into agreements with contract manufacturers and suppliers that either allow them to procure goods and services based upon specifications defined by us, or that establish parameters defining our requirements. At December 31, 2017, total obligations related to such supplier agreements were approximately $113.4 million (approximately $54.2 million of which relate to construction-in-process). All such obligations are payable in 2018.

The table above does not reflect unrecognized tax benefits of $8.9 million, the timing of which is uncertain. Refer to Note 18 to our consolidated financial statements set forth in Item 8 of this annual report for additional discussion of unrecognized tax benefits. The above table also does not reflect a liability associated with the sale of tax benefits of $44.6 million, the timing of which is uncertain. Refer to Note 13 to our consolidated financial statements as set forth in Item 8 of this annual report for additional discussion of our liability associated with the sale of tax benefits.

Concentration of Credit Risk

Our credit risk is currently concentrated with the following major customers: Southern California Edison, Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), KPLC, SCPPA and Hyundai. If any of these customers fails to make payments under its PPAs with us, such failure would have a material adverse impact on our financial condition. Also, by implementing our multi-year strategic plan we may be exposed, by expanding our customer base, to different credit profile customers than our current customers.

Southern California Edison accounted for 4.3%, 5.1%, and 9.4% of our total revenues for the three years ended December 31, 2017, 2016, and 2015, respectively. Southern California Edison is also the power purchaser and revenues source for our Mammoth project, which we accounted for separately under the equity method of accounting through August 1, 2010.

Sierra Pacific Power Company and Nevada Power Company accounted for 18.1%, 19.2%, and 19.5% of our total revenues for the three years ended December 31, 2017, 2016, and 2015, respectively.

KPLC accounted for 15.9%, 16.5%, and 14.6% of our total revenues for the three years ended December 31, 2017, 2016, and 2015, respectively.

SCPPA accounted for 10.1%, 10.2% and 5.2% of our total revenues for the three years ended December 31, 2017, 2016 and 2015, respectively.

Hyundai (Sarulla geothermal power project) accounted for 4.2%, 15.2% and 15.7% of our total revenues for the three years ended December 31, 2017, 2016 and 2015, respectively.

We have historically been able to collect on substantially all of our receivable balances. Recently, we have been receiving late payments from KPLC in Kenya related to our Olkaria Complex and from ENNE in Honduras related to our Platanares power plant. As we believe we will be able to collect all past due amounts, no provision for doubtful accounts has been recorded.

Tax Benefits

The federal government encourages production of electricity from geothermal resources or solar energy through certain tax subsidies. For a new geothermal power plant in the U.S. that started construction by December 31, 2017, we are permitted to claim an investment tax credit for 30 percent of the project cost in the year the project is put in service or production tax credits over time on the power produced. The production-based credits, which in 2017 were 2.4 cents per kWh, are adjusted annually for inflation and may be claimed for 10 years on the net electricity output sold to third parties after the project is first placed in service. Any project that started construction by December 2017 must ordinarily be put in service within four years after the end of the year in which construction started to qualify for tax credits at these rates. For a new geothermal power plant in the U.S. that started construction after 2017, we are permitted to claim an investment tax credit of 10 percent of the project cost.

New solar projects that are under construction by December 2019 will qualify for a 30 percent investment tax credit. The credit will fall to 26 percent for projects starting construction in 2020 and 22 percent for projects starting construction in 2021. Projects that are under construction before these deadlines must be placed in service by December, 31 2023 to qualify for investment tax credits at these rates. Solar projects placed in service after December, 31, 2023 will only qualify for a 10 percent investment tax credit, on par with the permanent credit provided to geothermal. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward.

We are also permitted to depreciate, or write off, most of the cost of the plant. In cases where we claim the one-time 30% (or 10%) tax credit, our tax basis in the plant that we can recover through depreciation is reduced by one-half of the tax credit. In cases where we claim the production tax credit, there is no reduction in the tax basis for depreciation. Projects that are placed in service in 2016 and 2017 are eligible for “bonus” depreciation and we will be permitted to write off 50% of the cost of that equipment in the year the power plant is placed in service. Projects placed in service in 2018 would qualify for a 40% bonus and Projects placed in service in 2019 would qualify for a 30% bonus. After applying any depreciation bonus that is available, we can write off the remainder of our tax basis in the plant, if any, over five years on an accelerated basis, meaning that more of the cost may be deducted in the first few years than during the remainder of the depreciation period. The Tax Act, as further discussed in the MD&A section allows full expensing for certain assets acquired and placed in service after September 27, 2017. The Company will continue to analyze this new provision under the Act and determine if an election is appropriate as it relates to their business needs**.**

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 through 2011. 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. As a result, we now pay a uniform corporate tax rate of 16% with respect to that qualified income.

Ormat Systems tax assessment for fiscal years 2010-2014 was finalized and settled in January 2017. The settlement resulted in no impact to income statement due to release of the related uncertain tax position liability.

As previously reported by the Company, the Kenya Revenue Authority (“KRA”) conducted an audit related to the Company’s operations in Kenya for fiscal years 2012 - 2013. In January 2017, KRA concluded its audit for the subject period and issued a demand letter to the Company for additional tax payments of approximately $16.1 million, including interest and penalties. KRA’s assessment, among other points, rejected the Company's income tax deduction of 150% of its investment in geothermal well drilling during the relevant period, on the basis that such work falls under mining activities (and not geothermal activities) which have a different allowable deduction under the Kenya Income Tax Act. The KRA audit and assessment is not final and is subject to objection by the Company. The Company's operations in Kenya utilize a geothermal resource license from the Ministry of Energy and Petroleum. The Company does not conduct and is not involved in any mining activity under applicable Kenyan law. Therefore, the Company believes that its original tax position was and remains correct under Kenyan tax law and regulations, and has submitted a notice of objection to the KRA, which it intends to pursue vigorously. If the KRA position prevails and is applied to subsequent periods, the Company's deferred tax asset of $49.4 million recorded in 2015 may be impacted. At present, the Company has recorded a provision based on its assessment of its reasonably expected potential exposure.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Information responding to Item 7A is included in Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of this annual report.

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ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***

Index to Consolidated Financial Statements of Ormat Technologies, Inc. and Subsidiaries

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Ormat Technologies, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Ormat Technologies, Inc. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO because a material weakness in internal control over financial reporting existed as of that date related to ineffective risk assessment over accounting for income taxes.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in Management's Report on Internal Control over Financial Reporting appearing in Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2017 consolidated financial statements, and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements.

Restatement of Previously Issued Financial Statements

As discussed in Note 1 to the consolidated financial statements, the Company has restated its 2017 financial statements to correct misstatements.

Management and we previously concluded that the Company did not maintain an effective internal control over financial reporting as of December 31, 2017 because of the material weakness related to ineffective risk assessment over accounting for income taxes. Management has determined that the restatement described in Note 1 to the consolidated financial statements was an additional effect of the material weakness described above. Accordingly, this restatement did not affect management's report or our opinion on internal control over financial reporting.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

San Francisco, California

March 16, 2018, except with respect to our opinion on the consolidated financial statements insofar as it relates to the effects of the restatement and revision discussed in Note 1, as to which the date is June 19, 2018.

We have served as the Company's auditor since 1988.

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES CONSOLIDATED BALANCE SHEETS

	December 31, 2017 (As restated)	December 31, 2016
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$*47,818*	$*230,214*
Restricted cash and cash equivalents (primarily related to VIEs)	*48,825*	*34,262*
Receivables:		
Trade	*110,410*	*80,807*
Other	*13,828*	*17,482*
Inventories	*19,551*	*12,000*
Costs and estimated earnings in excess of billings on uncompleted contracts	*40,945*	*52,198*
Prepaid expenses and other	*40,269*	*45,867*
Total current assets	*321,646*	*472,830*
Investment in an unconsolidated company	*34,084*	—
Deposits and other	*21,599*	*18,553*
Deferred income taxes	57,337	—
Deferred charges	*49,834*	*43,773*
Property, plant and equipment, net ($1,631,900 and $1,483,224 related to VIEs, respectively)	*1,734,691*	*1,556,378*
Construction-in-process ($142,717 and $120,853 related to VIEs, respectively)	*293,542*	*306,709*
Deferred financing and lease costs, net	*4,674*	*3,923*
Intangible assets, net	*85,420*	*52,753*
Goodwill	*21,037*	*6,650*
Total assets	$*2,623,864*	$*2,461,569*
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$*153,796*	$*91,650*
Short term revolving credit lines with banks (full recourse)	*51,500*	—
Billings in excess of costs and estimated earnings on uncompleted contracts	*20,241*	*31,630*
Current portion of long-term debt:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes	*33,226*	*32,234*
Other loans	*21,495*	*21,495*
Full recourse	*3,087*	*12,242*
Total current liabilities	*283,345*	*189,251*

Long-term debt, net of current portion:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes (less deferred financing costs of \$8,113 and \$9,177, respectively)	*311,668*	*350,388*
Other loans (less deferred financing costs of \$5,258 and \$6,409, respectively)	*242,385*	*261,845*
Full recourse:		
Senior unsecured bonds (less deferred financing costs of \$580 and \$755, respectively)	*203,752*	*203,577*
Other loans (less deferred financing costs of \$1,011 and \$1,346, respectively)	*46,489*	*57,063*
Investment in an unconsolidated company	—	*11,081*
Liability associated with sale of tax benefits	*44,634*	*54,662*
Deferred lease income	*51,520*	*54,561*
Deferred income taxes	*61,961*	*36,411*
Liability for unrecognized tax benefits	*8,890*	*6,444*
Liabilities for severance pay	*21,141*	*18,600*
Asset retirement obligation	*27,110*	*23,348*
Other long-term liabilities	*18,853*	*21,294*
Total liabilities	*1,321,748*	*1,288,525*
Commitments and contingencies (Note 22)		
Redeemable noncontrolling interest	*6,416*	*4,772*
Equity:		
The Company's stockholders' equity:		
Common stock, par value \$0.001 per share; 200,000,000 shares authorized; 50,609,051 and 49,667,340 shares issued and outstanding as of December 31, 2017 and December 31, 2016, respectively	*51*	*50*
Additional paid-in capital	*888,778*	*869,463*
Retained earnings	*327,255*	*215,352*
Accumulated other comprehensive loss	*(4,706)*	*(8,175)*
Total equity attributable to Company's stockholders	*1,211,378*	*1,076,690*
Noncontrolling interest	*84,322*	*91,582*
Total equity	*1,295,700*	*1,168,272*
Total liabilities, redeemable noncontrolling interest and equity	\$*2,623,864*	\$*2,461,569*

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2017 (As restated)	2016	2015
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$468,329	$436,292	$375,920
Product	224,483	226,299	218,724
Total revenues	692,812	662,591	594,644
Cost of revenues:			
Electricity	272,266	261,573	242,612
Product	152,094	130,223	133,753
Total cost of revenues	424,360	391,796	376,365
Gross profit	268,452	270,795	218,279
Operating expenses:			
Research and development expenses	3,157	2,762	1,780
Selling and marketing expenses	15,600	16,424	16,077
General and administrative expenses	42,881	46,710	34,782
Write-off of unsuccessful exploration activities	1,796	3,017	1,579
Operating income	205,018	201,882	164,061
Other income (expense):			
Interest income	988	971	297
Interest expense, net	(54,142)	(67,389)	(72,577)
Derivatives and foreign currency transaction gains (losses)	2,654	(5,534)	(1,622)
Income attributable to sale of tax benefits	17,878	16,503	25,431
Other non-operating expense, net	(1,666)	(5,345)	(1,991)
Income from continuing operations before income taxes and equity in losses of investees	170,730	141,088	113,599
Income tax (provision) benefit	(21,664)	(37,059)	16,057
Equity in earnings (losses) of investees, net	(1,957)	(7,735)	(5,508)
Income from continuing operations	147,109	96,294	124,148
Net income attributable to noncontrolling interest	(14,695)	(7,586)	(3,776)
Net income attributable to the Company's stockholders	$132,414	$88,708	$120,372
Comprehensive income:			
Net income	147,109	96,294	124,148
Other comprehensive income (loss), net of related taxes:			
Currency translation adjustments	3,440	(1,648)	—
Change in unrealized gains or losses in respect of the Company's share in derivatives instruments of unconsolidated investment	804	1,185	1,028
Loss in respect of derivative instruments designated for cash flow hedge	135	141	147
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	(73)	(96)	(118)

Comprehensive income	151,415	95,876	125,205
Comprehensive income attributable to noncontrolling interest	(15,532)	(7,179)	(3,776)
Comprehensive income attributable to the Company's stockholders	$135,883	$88,697	$121,429
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$2.64	$1.79	$2.48
Diluted:			
Net income	$2.61	$1.77	$2.45
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,110	49,469	48,562
Diluted	50,769	50,140	49,187
Dividend per share declared	$0.41	$0.52	$0.26

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF EQUITY

	The Company's Stockholders' Equity							
	Common Stock Shares	Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Total	Noncontrolling Interest	Total Equity
	(Dollars in thousands, except per share data)							
Balance at December 31, 2014	45,537	$ 46	$ 742,006	$ 44,670	$ (9,221)	$ 777,501	$ 11,823	$ 789,324
Stock-based compensation	—	—	3,955	—	—	3,955	—	3,955
Exercise of options by employees and directors	574	—	6,085	—	—	6,085	—	6,085
Share exchange with Parent	2,996	3	26,012	—	—	26,015	—	26,015
Cash paid to non controlling interest	—	—	—	—	—	—	(7,196)	(7,196)
Cash dividend declared, $0.26 per share	—	—	—	(12,716)	—	(12,716)	—	(12,716)
Issuance of shares to noncontrolling interest, net of transaction costs	—	—	71,165	—	—	71,165	85,470	156,635
Net income	—	—	—	120,372	—	120,372	3,776	124,148
Other comprehensive income (loss), net of related taxes:								
Loss in respect of derivative instruments designated for cash flow hedge	—	—	—	—	147	147	—	147
Change in unrealized gains or	—	—	—	—	1,028	1,028	—	1,028

losses in respect of the Company's share in derivative instruments of unconsolidated investment								
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $73)	—	—	—	—	(118)	(118)	—	(118)
Balance at December 31, 2015	49,107	$ 49	$ 849,223	$ 152,326	$ (8,164)	$ 993,434	$ 93,873	$ 1,087,307
Stock-based compensation	—	—	5,157	—	—	5,157	—	5,157
Exercise of options by employees and directors	560	1	7,249	—	—	7,250	—	7,250
Cash paid to non controlling interest	—	—	—	—	—	—	(57,391)	(57,391)
Cash dividend declared, $0.52 per share	—	—	—	(25,682)	—	(25,682)	—	(25,682)
Increase in noncontrolling interest in Guadeloupe	—	—	—	—	—	—	8,240	8,240
Increase in noncontrolling interest in Opal Geo	—	—	—	—	—	—	3,697	3,697
Issuance of shares to noncontrolling interest, net of transaction costs	—	—	7,834	—	—	7,834	36,268	44,102
Net income	—	—	—	88,708	—	88,708	7,302	96,010
Other comprehensive income (loss), net of related taxes:								
Currency translation adjustment	—	—	—	—	(1,241)	(1,241)	(407)	(1,648)
Loss in respect of derivative instruments designated for cash flow hedge	—	—	—	—	141	141	—	141
Change in unrealized gains or losses in respect of	—	—	—	—	1,185	1,185	—	1,185

the Company's share in derivative instruments of unconsolidated investment								
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $57)	—	—	—	—	(96)	(96)	—	(96)
Balance at December 31, 2016	49,667	$ 50	$ 869,463	$ 215,352	$ (8,175)	$ 1,076,690	$ 91,582	$ 1,168,272
Stock-based compensation	—	—	8,760	—	—	8,760	—	8,760
Exercise of options by employees and directors	942	1	16,111	—	—	16,112	—	16,112
Cash paid to noncontrolling interest	—	—	—	—	—	—	(21,313)	(21,313)
Cash dividend declared, $0.41 per share	—	—	—	(20,511)	—	(20,511)	—	(20,511)
Buyout of Class B membership in ORTP	—	—	2,913	—	—	2,913	(6,964)	(4,051)
Buyout of Class B membership in OPC	—	—	(8,469)	—	—	(8,469)	6,537	(1,932)
Net income (As restated)	—	—	—	132,414	—	132,414	13,643	146,057
Other comprehensive income (loss), net of related taxes:								
Currency translation adjustment	—	—	—	—	2,603	2,603	837	3,440
Loss in respect of derivative instruments designated for cash flow hedge (As restated)	—	—	—	—	135	135	—	135
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated	—	—	—	—	804	804	—	804

investment								
Amortization of unrealized gains in respect flow hedge (net of related tax of $46)	—	—	—	—	*(73*)	*(73*)	—	*(73*)
Balance at December 31, 2017 (As restated)	*50,609*	$ *51*	$ *888,778*	$ *327,255*	$ *(4,706*)	$ *1,211,378*	$ *84,322*	$ *1,295,700*

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017 (As restated)	2016	2015
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income	$147,109	$96,294	$124,148
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	115,146	105,977	107,206
Amortization of premium from senior unsecured bonds	—	(513)	(306)
Accretion of asset retirement obligation	1,874	1,778	1,198
Stock-based compensation	8,760	5,157	3,955
Amortization of deferred lease income	(2,685)	(2,685)	(2,685)
Income attributable to sale of tax benefits, net of interest expense	(11,956)	(6,962)	(17,467)
Equity in losses of investees	1,957	7,735	5,508
Mark-to-market of derivative instruments	(1,473)	319	4,129
Write-off of unsuccessful exploration activities	1,796	3,017	1,579
Gain on severance pay fund asset	(1,746)	(304)	(119)
Deferred income tax provision (benefit) and deferred charges	(41,147)	23,222	(39,962)
Liability for unrecognized tax benefits	3,270	(4,174)	3,107
Deferred lease revenues	(356)	(853)	224
Other	737	—	484
Changes in operating assets and liabilities, net of amounts acquired:			
Receivables	(24,040)	(33,280)	(3,806)
Costs and estimated earnings in excess of billings on uncompleted contracts	11,253	(27,078)	2,673
Inventories	(1,070)	6,297	(1,144)
Prepaid expenses and other	208	(12,540)	(2,579)
Deposits and other	(2,570)	(1,009)	(648)
Accounts payable and accrued expenses	51,641	(1,375)	(939)
Due from/to related entities, net	—	—	451
Billings in excess of costs and estimated earnings on uncompleted contracts	(11,389)	(2,262)	9,168
Liabilities for severance pay	2,541	(786)	(1,076)
Other long-term liabilities	(2,285)	3,310	(2,561)
Due from/to Parent	—	—	(513)
Net cash provided by operating activities	245,575	159,285	190,025
Cash flows from investing activities:			
Cash acquired in organizational restructuring and share exchange with parent	—	—	15,391
Net change in restricted cash, cash equivalents and marketable securities	(14,563)	15,241	43,745
Capital expenditures	(259,234)	(151,930)	(152,450)

Investment in unconsolidated companies	(46,318)	(3,569)	—
Buyout of Class B membership in ORTP	(2,400)	—	—
Buyout of Class B membership in OPC	(1,932)	—	—
Cash paid for acquisition of controlling interest in a subsidiary, net of cash acquired	(35,300)	(20,135)	—
Cash paid for achievement of production threshold in Guadeloupe	(8,032)	—	—
Intangible assets acquired	(868)	—	(500)
Decrease (increase) in severance pay fund asset, net of payments made to retired employees	526	1,862	2,843
Net cash used in investing activities	(368,121)	(158,531)	(90,971)
Cash flows from financing activities:			
Proceeds from sale of membership interests to noncontrolling interest, net of transaction costs	—	44,102	156,635
Proceeds from long-term loans, net of transaction costs	—	142,500	42,000
Proceeds from exercise of options by employees	16,111	7,249	6,085
Proceeds from issuance of senior unsecured notes, net of transaction costs	—	203,483	—
Purchase of Senior unsecured notes	—	(249,468)	—
Proceeds from the sale of limited liability company interest in Opal Geo LLC, net of transaction costs	—	59,897	—
Purchase of OFC Senior Secured Notes	(14,270)	(6,815)	(30,638)
Proceeds from revolving credit lines with banks	1,097,500	309,400	598,800
Repayment of revolving credit lines with banks	(1,046,000)	(309,400)	(619,100)
Cash received from noncontrolling interest	2,017	1,972	1,654
Repayments of long-term debt	(66,223)	(62,052)	(71,701)
Cash paid to noncontrolling interest	(21,313)	(64,065)	(19,068)
Payments of capital leases	(1,871)	(1,178)	—
Deferred debt issuance costs	(5,290)	(6,402)	(5,316)
Cash dividends paid	(20,511)	(25,682)	(12,716)
Net cash provided by (used in) financing activities	(59,850)	43,541	46,635
Net change in cash and cash equivalents	(182,396)	44,295	145,689
Cash and cash equivalents at beginning of period	230,214	185,919	40,230
Cash and cash equivalents at end of period	$47,818	$230,214	$185,919
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$40,484	$55,366	$55,492
Income taxes, net	$21,878	$18,490	$10,419
Supplemental non-cash investing and financing activities:			
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$4,484	$(2,219)	$3,810
Accrued liabilities related to financing activities	$—	$6,291	$1,665
Increase (decrease) in asset retirement cost and asset retirement obligation	$1,888	$714	$516

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE *1* — BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Business

Ormat Technologies, Inc. (the "Company") is primarily engaged in the geothermal and recovered energy business, including the supply of equipment that is manufactured by the Company and the design and construction of power plants for projects owned by the Company or for *third* parties. The Company owns and operates geothermal and recovered energy-based power plants in various countries, including the United States of America ("U.S."), Kenya, Guatemala, Guadeloupe and Honduras. The Company's equipment manufacturing operations are located in Israel.

Most of the Company's domestic power plant facilities are Qualifying Facilities under the Public Utility Regulatory Policies Act of *1978* ("PURPA"). The power purchase agreements ("PPAs") for certain of such facilities are dependent upon their maintaining Qualifying Facility status. Management believes that all of the facilities located in the U.S. were in compliance with Qualifying Facility status requirements as of *December 31, 2017.*

Restatement of previously issued consolidated financial statements

As described further in Note 18, in the second quarter of 2017, the Company partially released its valuation allowance against its U.S. deferred tax assets. During the first quarter of 2018, the Company concluded that there were material tax provision and related balance sheet errors in its previously issued 2017 financial statements, primarily relating to the Company's ability to utilize Federal tax credits in the U.S. prior to their expiration starting in 2027 and the resulting impact on the Company's deferred tax asset valuation allowance, and the inappropriate netting of certain deferred income tax assets and deferred income tax liabilities across different tax jurisdictions that was not permissible under U.S. generally accepted accounting principles. In addition, there were other immaterial prior period errors, including an out-of-period adjustment that had been previously recorded for the correction of an understated liability for unrecognized tax benefits related to intercompany interest.

The error in the deferred tax asset valuation allowance resulted in an understatement of the income tax provision and net income in the previously reported 2017 consolidated statement of operations and comprehensive income of $23.1 million (see also Note 23 for the impact of such error on the 2017 unaudited quarterly financial statements). The impact of the errors on the previously reported December 31, 2017 consolidated balance sheet was an understatement of deferred tax liabilities and deferred tax assets of $62.0 million, for the error in netting certain deferred income tax assets and liabilities across different tax jurisdictions, offset by an overstatement in deferred tax assets of $24.8 million, primarily related to the valuation allowance errors described above, resulting in a net understatement in deferred tax assets of $37.2 million. In addition, previously reported December 31, 2017 retained earnings was overstated by $24.4 million and accumulated other comprehensive loss was understated by $0.4 million, representing the impact of all tax and tax-related errors dating back to 2013.

As a result of such errors, the Company concluded that the previously issued 2017 consolidated financial statements were materially misstated and has restated these financial statements.

Revision of previously issued consolidated financial statements

The Company had previously identified certain other tax errors, including a prior period error related to the translation of deferred tax liabilities in the Company's Kenyan subsidiary, which were previously determined to be immaterial. Accordingly, those amounts are also being corrected and reflected in the appropriate periods.

The Company assessed the materiality of these tax and tax related errors impacting 2015 and 2016 in accordance with the SEC's Staff Accounting Bulletin ("SAB") Topic 1.M, Materiality, codified in ASC Topic 250, Presentation of Financial Statements ("ASC 250"), and concluded that the previously issued 2016 and 2015 consolidated financial statements were not materially misstated; however, in order to correctly reflect the adjustments as described above in the appropriate period, management has elected to revise the affected previously issued financial statements in this Form 10-K/A filing. As a result, the revised 2015 consolidated financial statements reflect a $0.8 million increase in the tax benefit, net income and comprehensive income and the revised 2016 consolidated financial statements reflect a $5.2 million increase in the tax provision and a corresponding reduction in net income and comprehensive income. Certain of these errors originated in years prior to 2015, and accordingly retained earnings as of January 1, 2015 has been increased by $3.1 million to correct for those errors originating prior to 2015.

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The effects of the 2017 restatement and the 2016 revision on the line items within the Company's consolidated balance sheets as of December 31, 2017 and 2016 are as follows (in thousands):

	December 31, 2017			December 31, 2016		
	As originally reported	Adjustments	As Restated	As originally reported	Adjustments	As Revised
Deferred income tax assets	20,135	37,202	57,337	-	-	-
Total assets	2,586,662	37,202	2,623,864	2,461,569	-	2,461,569
Deferred income tax liabilities	-	61,961	61,961	35,382	1,029	36,411
Liability for unrecognized tax benefits	8,890	-	8,890	5,738	706	6,444
Total liabilities	1,259,787	61,961	1,321,748	1,286,790	1,735	1,288,525
Retained earnings	351,622	(24,367)	327,255	216,644	(1,292)	215,352
Accumulated other comprehensive loss	(4,314)	(392)	(4,706)	(7,732)	(443)	(8,175)
Total stockholders' equity attributable to the Company's stockholders	1,236,137	(24,759)	1,211,378	1,078,425	(1,735)	1,076,690
Total equity	1,320,459	(24,759)	1,295,700	1,170,007	(1,735)	1,168,272

The effects of the restatement and revision on the line items within the Company's consolidated statements of operations and comprehensive income for the years ended December 31, 2017, 2016 and 2015 are as follows (in thousands):

	Year ended December 31, 2017			Year ended December 31, 2016			Year ended December 31, 2015		
	As originally reported	Adjustments	As Restated	As originally reported	Adjustments	As Revised	As originally reported	Adjustments	As Revised
Income tax (provision) benefit	$1,411	$ (23,075)	$(21,664)	$(31,837)	$ (5,222)	$(37,059)	$15,258		