ORMAT TECHNOLOGIES, INC.
Form 10-K
March 01, 2019

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2018
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)*
6140 Plumas Street, Reno, Nevada	**89519-6075**
(Address of principal executive offices)	*(Zip 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 every Interactive Data File required to be submitted 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 such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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
			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, 2018, 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 $2,108,534,590 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 26, 2019, the number of outstanding shares of common stock, par value $0.001 per share was 50,702,174.

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, 2018.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2018

TABLE OF CONTENTS

Table of Contents

Glossary of Terms

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

Term	Definition
ACUA	Atlantic County Utilities Authority
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.
BEAT	Base Erosion Anti-Abuse Tax
BESS	Battery Energy Storage Systems
BLM	Bureau of Land Management of the U.S. Department of the Interior
BOT	Build, operate and transfer
BSAAS	Battary Storage as a Servise
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
CCA	
CDC	Caisse des Dépôts et Consignations, a French state-owned financial organization
CEO	Chief Executive Officer
CFO	Chief Financial Officer
C&I	Refers to the Commercial and Industrial sectors, excluding residential
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
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
EBITDA	Earnings before interest, taxes, depreciation and amortization
EDF	Electricite de France S.A.

EGS	Enhanced Geothermal Systems
EIB	European Investment Bank
EMRA	Energy Market Regulatory Authority in Turkey
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.

Table of Contents

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.
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
GW	Giga watt
GWh	Giga watt hour
HELCO	Hawaii Electric Light Company
IDWR	Idaho Department of Water
IGA	International Geothermal Association
IID	Imperial Irrigation District
INDE	Instituto Nacional de Electrification
IOUs	Investor-Owned Utilities
IPPs	Independent Power Producers
IESO	The Independent Electricity System Operator (IESO) works at the heart of Ontario's power system.
IRS	Internal Revenue Service
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
KGRA	Known Geothermal Area
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
LADWP	Los Angeles Department of Water and Power

LCOE	Levelized Costs of Energy
	Load Serving Entities
Mammoth Pacific	Mammoth-Pacific, L.P.
MACRS	Modified Accelerated Cost Recovery System
MW	Megawatt - One MW is equal to 1,000 kW or one million watts
MWh	Megawatt hour(s), a measure of energy produced

Table of Contents

NBPL	Northern Border Pipe Line Company
NIS	New Israeli Shekel
NOC	Network Operations Center
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
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
ORC	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
ORIX	ORIC Corporation
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

Table of Contents

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
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
REC	Renewable Energy Credit
REG	Recovered Energy Generation
RER	Renewable Energy Resource certificate
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
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
TASE	Tel Aviv Stock Exchange
Tax Act	Tax Cuts and Jobs Act
UIC	Underground Injection Control
Union Bank	Union Bank, N.A.
U.S.	United States of America
U.S. Treasury	U.S. Department of the Treasury
USG	U.S. Geothermal Inc.

VAT	Value Added Tax
VEI	Viridity Energy, Inc.
Viridity	Viridity Energy Solutions Inc., our wholly owned subsidiary
WHOH	Waste Heat Oil Heaters

Table of Contents

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 attributable to a number of risks and uncertainties, many of which are beyond our control.

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

significant considerations, risks and uncertainties discussed in this 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;

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

political, legal, regulatory, governmental, administrative and economic conditions and developments in the U.S., Turkey and other countries in which we operate and, in particular, possible import tariffs, possible late payments, 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 U.S., Turkey and elsewhere, and carbon-related legislation;

risks and uncertainty with respect to our internal control over financial reporting, including the identification of a material weakness which, if not timely remediated, may adversely affect the accuracy and reliability of our financial statements;

the impact of fluctuations in oil and natural gas prices under certain of our PPAs;

the competition with other renewable sources or a combination of renewable sources on the energy price component under future 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 profitability of such projects;

Table of Contents

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;

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

contract counterparty risk, including late payments or no payments;

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;

our ability to access the public markets for debt or equity capital quickly;

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;

when, if and to what extent opportunities under our commercial cooperation agreement with ORIX Corporation may 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, if any, may not materialize as planned; and 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.

Table of Contents

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.

Overview

We are a leading vertically integrated company that is primarily engaged in the geothermal and recovered energy power businesses. We are also expanding into the storage, demand response and energy management business.

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 objective is to become a leading global provider of renewable energy and we have adopted a strategic plan to focus on several key initiatives to expand our business.

Our owned geothermal power plants include both power plants that we have built and power plants that we have acquired. 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 year-long and all day-long and can provide base-load electricity services. Geothermal power plants can also be custom built to provide a range of electricity services such as baseload, voltage regulation, reserves and flexible capacity. Geothermal energy is also an attractive alternative to other sources of energy to support a diversification strategy to avoid dependence on any one energy source or politically sensitive supply sources.

In addition to our geothermal energy business, we manufacture and sell products that produce electricity from recovered energy or so-called “waste heat”. We also construct, own, and operate recovered energy-based power plants. We have built all of the recovered energy-based plants that we operate. 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.

In March 2017, we entered the energy storage, demand response and energy management markets following the acquisition of substantially all of the business and assets of Viridity Energy, Inc., a Philadelphia-based company. The acquired business and assets comprise our Other segment. We are using 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.

We currently conduct our business activities in three business segments:

Electricity Segment. 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.

Product Segment. 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, Solar PV and recovered energy-based power plants.

Other Segment. In the Other segment, we provide energy storage, demand response and energy management related services as well as services relating to the engineering, procurement, construction, operation and maintenance of energy storage units mainly through our Viridity business.

Business Strategy

Our strategy is focused on further developing a geographically balanced portfolio of geothermal and recovered energy assets and continuing our leading position in the geothermal energy market with the objective of becoming a leading global provider of renewable energy. 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 all business segments. While we continue to evaluate global opportunities, we currently see Turkey, New Zealand, Chile, Kenya, Honduras, China, Indonesia and Ethiopia as 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 additional geothermal assets as well as technologies and projects that can support our storage business.

- *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 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 and CCA markets. In the near term, however, we expect that the majority of our revenues will continue to be generated, 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.

Table of Contents

The map below shows our worldwide portfolio of operating geothermal and recovered energy power plants as of February 26, 2019.

* In the Sarulla project, we include our 12.75% share only.

The charts below show the relative contributions of each of our segments to our consolidated revenues and the geographical breakdown of our segment revenues for the fiscal year ended December 31, 2018. 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 — "Financia Statements and Supplementary Data".

Table of Contents

The following chart sets forth a breakdown of our revenues for each of the years ended December 31, 2017 and 2018 (*):

(*) The contribution of the Other segment to revenues in 2017 was lower than 0.5% and therefore rounded down to 0% in the graph above.

The following chart sets forth the geographical breakdown of revenues attributable to our Electricity, Product and Other segments for each of the years ended December 31, 2017 and 2018:

Table of Contents

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.

Our reports on Forms 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 biennial Sustainability Report, 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.

Table of Contents

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 February 26, 2019. The generating capacity of certain of our power plants and complexes listed below has been updated from our 2017 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 2018 Capacity Factor**
Geothermal	California	Ormesa Complex	100%	39	
		Heber Complex	100%	81	
		Mammoth Complex	100%	29	
		Brawley	100%	13	
					75%
	West Nevada	Steamboat Complex	100%	65	
		Brady Complex	100%	26	
					85%
	East Nevada	Tuscarora	100%	18	
		Jersey Valley	100%	10	
		McGinness Hills	100%	140[4]	
		Don A. Campbell	63.3%	39	
		Tungsten Mountain	100%	27	
					92%
	North West Region	Neal Hot Springs[7]	60%	22[8]	
		Raft River[7]	100%	11	
		San Emidio[7]	100%	11	
					88%
	Hawaii	Puna	63.3%	38	
					33%[10]
	International	Amatitlan (Guatemala)	100%	20	
		Zunil (Guatemala)	97%	23	
		Olkaria III Complex (Kenya)	100%	150[6]	
		Bouillante (Guadeloupe Island)	60%[4]	15	
		Platanares (Honduras)	100%	38	
					95%
Total Consolidated				815	88%[10]

Geothermal					
Unconsolidated Geothermal	Indonesia	Sarulla (SIL & NIL 1)	12.75%	42	
REG		OREG 1	63.3%	22	
		OREG 2	63.3%	22	
		OREG 3	63.3%	5.5	
		OREG 4	100%	3.5(7)	
Total REG				53	78%
Total				**910**	

13

Table of Contents

1. We indirectly own and operate all of our power plants, although financial institutions hold equity interests in one of our Opal Geo subsidiaries, which owns the McGinness Hills Phases 1 and 2 geothermal power plants, 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 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 Transaction".

Notwithstanding our approximate 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, 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 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.

3. 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.

4. The McGinness Hills complex includes 48MW of phase 3 that reached commercial operation in December 2018.

5. We own 63.75%, CDC owns 21.25% and Sageos own 15%, of the Bouillante power plant.

6. The Olkaria complex includes a 11MW repowering addition that reached commercial operation on June 2, 2018.

7. 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.

8. The Neal Hot Springs, Raft River and San Emidio are power plants that we acquired in April 2018 while acquiring US Geothermal Inc.

9. We own 60% and Enbridge own 40% of the Neal Hot Springs power plant.

10. The Puna geothermal power plant was shut down since May 3, 2018, when the Kilauea volcano located in close proximity to it erupted following a significant increase in seismic activity in the area. We are working to bring the power plant back to operation.

11. The total availability of the geothermal power plants excludes the Zunil power plant as its generating capacity is determined unrelated to its performance and the Puna power plant that is not in operation, both as discussed above.

All of the revenues that we derive from the sale of electricity are pursuant to long-term PPAs. Approximately 34.9% of our total revenues in the year ended December 31, 2018 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 mainly state-owned 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 37 MW in generating capacity from geothermal and Solar PV power plants in the United States that we fully released for construction. In addition, we have several geothermal and Solar PV projects in the U.S. and Guadeloupe that are either under initial stages of construction or under different stages of development with an aggregate capacity of between 130 MW and 150 MW.

We have substantial land positions across 38 prospects, 28 prospects in the U.S., and 10 prospects in Ethiopia, Guadeloupe, Guatemala, Honduras, Indonesia and New Zealand that we expect will support future geothermal development and 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 leases.

In addition, we are currently developing a storage system in Georgetown, Texas.

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 projects that we will own and for future third party 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 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, 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 that our competitive advantage is in using equipment that we manufacture and thus have better quality and better control over the timing and delivery of required equipment and their 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 offshore 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 winding down these activities.

Our New Activity (Our Other Segment)

Our storage business currently manages, through the Viridity platform, 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 NOC, which is operated 24/7 using our VPower™ 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 ecosystem we created, combining our Viridity capabilities and our legacy Ormat capabilities, including among others, our global presence, experience in technology and system integration, development and 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.

Our Viridity business obtained and maintains authorization from FERC to make wholesale purchase and sales of energy, 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, NYISO, and the ERCOT. Additionally, during the fourth quarter of 2017, we received formal notice of membership in MISO and ISO New England Inc. and have filed for membership in 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.

Table of Contents

In 2018, we successfully brought on line our first two Ormat/Viridity-owned BESS projects: 1 MW / 1 MWh in Atlantic City, NJ and 20 MW / 20 MWh in Plumsted, NJ. We also started construction of another 20 MW/ 20 MWh project in Alpha, NJ and continued developing a 10 MW / 12.5 MWh project in Georgetown, Texas. We plan to continue and leverage our worldwide experience in project development and finance, as well as relationships with utilities and other market participants, to develop additional such BESS projects in the U.S. and internationally.

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

There are several different sources or methods of obtaining geothermal energy, which are described below.

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 because 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.

Table of Contents

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 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.

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.

Table of Contents

Our Proprietary Technology

Our proprietary technology may be used either in power plants operating according to the ORC 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). By 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.

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 consequently 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 erosive and corrosive. 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 ORC. 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.

Table of Contents

Our REG technology is depicted in the diagram below.

Patents

We have 77 U.S. patents that are in force (and have nine U.S. patents pending). These patents and patent applications cover our products (mainly power units based on the ORC) 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, reinjection of other geothermal fluids ensuring geothermal resource sustainability, 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 conduct 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, building of an energy storage lab for testing of various batteries, inverters and the integration of both. 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 VPowerTM software and SCADA platform to accelerate system optimization through cloud base algorithms.

Table of Contents

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 Opportunities

Geothermal Market Opportunities

Renewable energy in general provides a sustainable alternative to the existing solutions to two major global issues: global warming and diminishing fossil fuel reserves. Renewable energy is sustainable and clean, as it emits no or negligible amounts of CO2. These environmental benefits have led major countries to focus their efforts on the development of renewable energy sources in general and geothermal specifically.

Today, based on an announcement by the IGA on February 2019, geothermal power is generated in 27 countries with a total installed power generation capacity of 14,600 MW at the end of 2018. The leading countries are the U.S., Indonesia, Philippines, Turkey and New Zealand. The IGA expects that 4,100 MW will be added by 2023.

Having realized the importance of renewable energy including geothermal alternatives, various governments have been preparing regulatory frameworks and policies, and providing incentives to develop the sector.

United States

RPSs or quota obligations, and FITs are the two most prominent support mechanisms that have been aiding the development of the renewable energy market in the U.S. With the identification of these mechanisms, most of the countries have framed their policies incorporating these measures.

Interest in geothermal energy in the U.S. remains strong for numerous reasons, including the legislative support, RPS goals (as described below), coal and nuclear base-load retirements, and an 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.

Geothermal energy provides numerous benefits to the U.S. grid and economy, according to a GEA report issued in January 2017. Geothermal development and operation bring 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.

Federal tax initiatives

The U.S. federal government encourages production of electricity from geothermal resources or solar energy through certain tax subsidies:

- PTC - the PTC provides per kWh credit on tax paid by power producers for power produced from geothermal resources and certain other renewable energy sources and sold to an unrelated person during a taxable year. The PTC was first introduced in 1992 and has since been revised a number of times. The ARRA, which came into effect in February 2009, contains a number of important measures related to the US renewable energy industry aimed at encouraging continued growth. The PTC, which in 2018 was 2.4 cents per kWh, is 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 31, 2018 must ordinarily be put in service within four years after the end of the year in which construction started or show continued construction to qualify for tax credits at these rates. The PTC is not available for power produced from geothermal resources for projects that started construction on or after January 1, 2018.

Table of Contents

- ITC - the ITC has been amended a number of times. For a new geothermal power plant in the United States that started construction after 2017, we are permitted to claim an ITC of 10 percent of the project cost. New solar projects that are under construction by December 2019 will qualify for a 30 percent ITC. The credit will fall to 26 percent for Solar PV projects starting construction in 2020 and 22 percent for Solar PV 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 an investment tax credit at these rates. Solar projects placed in service after December 31, 2023 will only qualify for a 10 percent ITC. Under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward.

- On December 22, 2017, the U.S. President signed into law the Tax Act, which made changes that have some impact on the renewable energy industry. Some of the key changes are as follows:

  - The U.S. corporate income tax rate was reduced from 35% to 21% beginning in 2018.

  - Bonus depreciation was increased from 40% expensing of qualified projects in year one to 100% beginning in on September 27, 2017. The 100% expensing is valid through 2022 and then declines through 2026.

  - The BEAT provision is a new tax intended to apply to companies that significantly reduce their U.S. tax liability by making cross-border payments to affiliates. The provision aims to circumvent earnings stripping by imposing a minimum tax of 10% of taxable income. ITC and PTC can be used to offset approximately 80% BEAT. See the discussion under Item 1A — “Risk Factors”.

State level legislation

State governments have embarked on a program called RPS, under which utilities are required to include renewable energy sources as part of their energy generation. Under the RPS, participating states have set targets for the production of their energy from renewable sources by specified dates. Related to the RPS program is the REC initiative, under which utilities can support renewable energy generation and obtain certificates, which can be used to achieve the mandate prescribed by the RPS.

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 National Conference of State Legislatures, 29 states, three territories, and the District of Columbia have set renewable energy goals. The vast majority of Ormat’s geothermal projects can be found in California, Nevada, and Hawaii which have some of the highest RPS standards in the country.

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

Below are RPS targets in the states in which we are operating in:

State	**Share**	**Year**	**Remarks**
California	60%	2030	RPS targets set for future years: 33% – 2020, 40% – 2024, and 45% – 2027. 100% zero carbon by 2045.
Nevada	40%	2030	For solar power, there is a 6% of annual requirement for 2016–2025, 25%-2030
Hawaii	100%	2045	RPS targets set for future years: 30% – 2020, 40% – 2030, and 70% – 2040
Oregon	25%	2025	This as well as an Increased RPS of 50% by 2040 applies to IOU who have a share of more than 3% of the state's load; for utilities with a load-share of 1.5% – 3%, requirement is 10% in 2025, and for utilities with a load share of less than 1.5%, it is 5% in 2025
Utah	20%	2025	

Table of Contents

Global

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

Operations outside of the United States 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 by the International Renewable Energy Agency entitled Rethinking Energy, more than 170 countries to date have established renewable energy targets, and nearly 150 have enacted policies to catalyze investments in renewable energy technologies.

We believe that several global initiatives will create business opportunities and support global growth of the renewable sector such as the historic agreement at the COP21 UN Climate Change Conference held in Paris, which, for the first time, created a commitment by 127 parties to setting nationally determined climate targets and reporting on their progress. Following this agreement, the EIB and other multilateral institutions have committed to provide $100 billion of new financing for climate action projects over the next five years to assist countries in reaching their targets.

In addition, in 2015, a group of 20 countries, including the United States, United Kingdom, France, China and India, pledged to double their respective budgets for renewable energy technology over five years as part of a separate initiative called Mission Innovation. At the same time, 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.

On June 1, 2017, President Donald J. Trump announced that the United States 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.

We believe that these developments and governmental plans will create for us growth and expansion opportunities internationally.

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, sell products and/or are conducting business development activities:

Europe

Turkey

Until recently, Turkey was 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. Due to economic developments in this region, there has been a slowdown.

Since 2004, we have established strong business relationships in the Turkish market and provided our range of solutions including our binary systems to 40 geothermal power plants with a total capacity of nearly 855 MW, of which six 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.

Table of Contents

Iceland

Iceland has gone through several legislative and regulatory changes in recent years and the tariff for geothermal energy is no longer linked to the price of aluminum as it used to be, but rather is regulated independently. As a result, we anticipate growth in demand for geothermal power solutions in the country.

Latin America

Guatemala

In Guatemala, where our Zunil and Amatitlan power plants are located, the government approved and adopted the Energy Policy 2013-2027 that secure, among other things, a supply of electricity at competitive prices by diversifying the energy mix with an 80% renewable energy share target for 2027.

Honduras

In Honduras, where we operate our Platanares power plant, the government set a target to reach at least 80% renewable energy production by 2034.

Mexico

In Mexico, where we see long-term potential, the Mexican Congress passed, in December 2013, a constitutional reform in an attempt to increase the participation of private investors in the generation and commercialization of electric energy. We have not yet seen yet a notable progress in the development of new geothermal projects.

Ecuador

In Ecuador, which does not have any geothermal power plants online yet, aims to reach 90% clean energy and its National Energy Agenda estimates a local geothermal potential of 1,000 MW.

Caribbean

Many island nations in general and specifically the Caribbean nations, depend almost entirely on petroleum to meet their electricity needs. Caribbean nations have quite significant renewable energy potential, yet most have relatively small demand. Other than in Guadeloupe, where the geothermal power plant that we acquired has been operating since 1985, there are no other operating geothermal projects in the Caribbean region. Although few, we believe there are geothermal opportunities for us in the Caribbean islands of St. Kitts, Nevis, St. Lucia, Dominica, and Montserrat.

New Zealand

In New Zealand, where we have been actively providing geothermal power plant solutions since 1988, the government's policies to fight climate change include a 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, secured two projects in the last two years and intensified our cooperation with other potential customers for adding more geothermal power generation capacity within the coming years.

Asia

Indonesia

In Indonesia**,** where we hold a 12.75% equity interest in the Sarulla project, the 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 and announced its intention to reduce the country's carbon dioxide emissions by 26% by 2020. Under the local regulation, the tariff policy for geothermal PPAs is mainly determined based on the location of the relevant power plant.

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

23

China

In China, where we recently supplied our equipment to one of our clients' geothermal projects, the National Energy Administration adopted the 13^{th} Renewable Energy Development Five Year Plan that 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.

Kenya

In Kenya, there are already several geothermal power plants, including the only geothermal IPP in Africa, our 150 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.

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).

Other Countries

The governments of Djibouti, Eritrea, Ethiopia, 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.

Ethiopia electrification targets for 2025 require additional investment in generation capacities. Such growth in demand will be principally met with the Grand Ethiopian Renaissance Dam (GERD). However, IPP's are encouraged to participate directly into the renewable development in order to meet expected local growth. Moreover, the current government sees electricity export to neighboring countries as a strategic asset. The country recently completed an interconnection with Kenya and plan to further increase connections to Djibouti, Sudan, South Sudan, Rwanda, Burundi. These exports will improve foreign exchange reserves in Ethiopia while reducing exposure to fossil fuel imports. We hold rights for four geothermal concessions in Ethiopia, for which we have completed initial exploration studies.

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

<u>*Recovered Energy Generation*</u>

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. We have built 23 power plants which generate electricity utilizing "waste heat" from gas turbine-driven compressor stations along interstate natural gas pipelines, from midstream and gas processing facilities, and from other applications.

Several states, and to some 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.

Table of Contents

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 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.

Energy Storage

Globally, there is an increase in the use of renewable energy due to the continued decline in Solar PV prices. In the United States and Europe, this increase is placing strains on the electric grid because adding Solar PV power creates 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. Furthermore, 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 cause instability on the electric grid.

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

Energy storage systems utilize surplus, available electricity that enables utilities to optimize the operation of the grid, run generators closer to full capacity for longer periods, and operate the grid more efficiently and effectively. As penetration of wind and solar resources increases, so does the need for services that energy storage systems can provide to “balance the grid”, such as local capacity, frequency regulation, ramping, reactive power, black start and movement of energy from times of excess supply to times of high demand. Common applications for energy storage systems include ancillary services, wind/solar smoothing, Peaker replacement, and transmission & distribution deferral.

The global energy storage market continues to evolve, with specific applications and geographies leading the market. According to Greentech Media, approximately 4.5 GWh of new energy storage projects were installed in 2018 and this number is expected to almost double in 2019 to approximately 8 GWh.

Significant growth in BESS deployment is already taking place and is expected to continue for both grid-connected (also referred to as “in front of the meter”) applications, as well as for “behind the meter” applications, where end-users benefit from savings through demand charge reductions and create revenues through active market participation, through demand response programs. Many power systems are also undergoing significant changes such as grid aging, grid congestion, retirement of aging generators, implementation of greenhouse gas emission reduction rules and increasing penetration of variable renewable energy resources.

According to the December 2018 U.S. energy storage monitor by Wood Mackenzie Power & Renewables and Energy Storage Association, the behind-the-meter segment has grown significantly in 2018 and now accounts for roughly half of the annual U.S. market. This is driven by many factors including improved system economics, economic incentives provided by some states, 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. Similar trends to those currently seen in selected U.S. markets are expected to be prevalent in other global markets in Europe and Asia.

We plan to use our Viridity software 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.

Table of Contents

Grid-Connected BESS

We own and operate several grid-connected BESS facilities, where revenues come from selling energy, capacity and/or ancillary services in merchant markets like PJM Interconnect. We are pursuing the development of additional grid-connected BESS projects in multiple regions, with expected revenues coming from providing energy, capacity and/or ancillary services on a merchant basis, and/or through bilateral contracts with load serving entities, e.g. investor owned utilities, publicly owned utilities and community choice aggregators.

C&I

The electricity industry continues to shift from a purely centralized topology where electricity flows only in one direction from centralized power plants to consumers, into a more distributed architecture, that includes distributed energy resources and consumers selling excess electricity generated on-site to the grid. Many C&I companies are motivated to purchase renewable energy to meet sustainability goals and reduce costs. We see the C&I segment as a natural expansion of our customer base.

Solar PV

The Solar PV market continues to grow, driven by constant decline in equipment prices and an increasing desire to replace conventional generation with renewable resources, commonly supported by favorable regulatory policies. 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 current focus is in adding Solar PV systems in some of our operating geothermal power plants to reduce internal consumption loads, developing standalone Solar PV projects in targeted regions where economics are favorable as well as developing combined Solar PV and BESS projects. We are currently constructing a Solar PV augmentation system at our Tungsten Mountain geothermal power plant in Churchill County, Nevada. We are also developing the 20 MW/AC Wister Solar PV project in Imperial County, California, for which a power purchase agreement with San Diego Gas & Electric was executed and received regulatory approval in 2018. Additional potential projects are undergoing feasibility analysis, and some are in earlier phases of development.

Recent Developments

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

- On December 20, 2018, we announced that the third phase of the McGinness Hills geothermal complex located in Lander County, Nevada had begun commercial operation. The 48-megawatt (net capacity) power plant started selling electricity to SCPPA under the Ormat Northern Nevada Geothermal Portfolio Power Purchase Agreement. SCPPA resells the entire output of the plant to the LADWP. The third phase is expected to generate approximately $30 million in average annual revenue.

- On October 31, 2018, we announced the completion of the closing of the finance agreement totaling $124.7 million in the aggregate for the 35 MW Platanares geothermal power plant in Honduras, with OPIC, the United States government's development finance institution, as the sole lender. Following the closing we received a disbursement of $114.7 million representing the full amount of Tranche I of the OPIC non-recourse project finance loan that carries a fixed interest rate of 7.02% per annum with a maturity of approximately 14 years. The second tranche of up to $10 million is expected during the first half of 2019.

- On September 30, 2018, we signed the termination of the Galena 2 Power PPA with NV Energy and agreed to pay a termination fee of approximately $5 million. The Galena 2 geothermal power plant was designated as a facility under the portfolio PPA that we signed with SCPPA in October 2016 and it is expected to start selling electricity to SCPPA in March 2019.

- In July 2018 we received a full notice to proceed for the $36 million EPC contract with Cyrq Energy Inc. for their Soda Lake 3 geothermal project in Nevada. This contract contributed part of its revenues to the Product segment in 2018.

- On June 27, 2018, we announced that the 11 MW Plant 1 expansion project in the Olkaria III complex in Kenya successfully completed its tests and commenced commercial operation on June 2, 2018. Between 2000 and 2018, the Company developed and expanded the Olkaria III complex in phases and increased its generating capacity from 13 MW to 150 MW.

- On May 17, 2018, one of our wholly-owned subsidiaries that indirectly owns the 26 MW Tungsten Mountain Geothermal power plant entered into a partnership agreement with a private investor. This private investor acquired membership interests in the Tungsten Mountain Geothermal power plant project for an initial purchase price of approximately $33.4 million and for which it will pay additional installments that are expected to amount to approximately $13 million. We will continue to operate and maintain the power plant and will receive substantially all the distributable cash flow generated by the power plant.

Table of Contents

- On May 8, 2018, we announced that NIL 2, the third unit of the Sarulla geothermal power plant, commenced commercial operation on May 4, 2018, and the Sarulla power plant reached its full capacity of 330 MW. SIL, the first unit of the power plant commenced commercial operation in March 2017 and NIL 1, the second unit, commenced commercial operation in October 2017.

- On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. Before it recently stopped flowing, the lava covered the wellheads of three geothermal wells, monitoring wells and the substation of the Puna complex and an adjacent warehouse that stored a drilling rig that was also consumed by the lava. The insurance policy coverage for property and business interruption is provided by a consortium of insurers. All the insurers accepted and started paying for the costs to rebuild the destroyed substation, and as of December 31, 2018 we received $3.3 million. However, only some of the insurers accepted that the business interruption coverage started in May 2018 and as of December 31, 2018, we recorded $12.1 million of such proceeds. We are still in discussions to reach an understanding with all insurers to start paying for the business interruption as of May 2018. The Company is still assessing the damages in the Puna facilities and continue to coordinate with HELCO and local authorities to bring the power plant back to operation. The Company continues to assess the accounting implications of this event on the assets and liabilities on its balance sheet and whether an impairment will be required. Any significant physical damage to the geothermal resource or continued shut-down following the recent stop of the lava of the Puna facilities could have an adverse impact on the power plant's electricity generation and availability, which in turn could have a material adverse impact on our business and results of operations.

- On April 24, 2018, we completed our acquisition of USG. The total cash consideration (exclusive of transaction expenses) was approximately $110 million, comprised of approximately $106 million funded from available cash of Ormat Nevada (to acquire the outstanding shares of common stock of USG) and approximately $4 million funded from available cash of USG (to cash-settle outstanding in-the-money options for common stock of USG). As a result of the acquisition, USG became an indirect wholly owned subsidiary of the Company, and the Company indirectly acquired, among other things, interests held by USG and its subsidiaries in:

  - three operating power plants at Neal Hot Springs, Oregon, San Emidio, Nevada and Raft River, Idaho with a total net generating capacity of approximately 38 MW (the USG Operating Projects); and

  - development assets at the Geysers, California; a second phase project at San Emidio, Nevada; a greenfield project in Crescent Valley, Nevada; and the El Ceibillo project located near Guatemala City, Guatemala (the “USG Development Projects”)

- On April 16, 2018, we announced that our Viridity subsidiary expected to start construction of two 20MW/20MWh utility scale, in-front-of-the-meter battery energy storage systems (BESS) located in Plumsted Township and Alpha, New Jersey. The two system started operation during the first quarter of 2019. Through Viridity, we will finance, construct, own and operate the projects. The BESS will be utilized to provide ancillary services to assist PJM Interconnection, a regional transmission organization, in balancing the electric grid, and will also be available as a capacity asset. The two projects together are expected to generate, in 2019, average revenues of between $7 million and $8 million, mainly from ancillary services. The projects derive revenue from the PJM ancillary service and electricity market which is a merchant market and subject to fluctuation.

- On March 22, 2018, we entered into a loan agreement with affiliates of the Migdal Group, one of Israel's leading insurance companies and institutional investors, to provide us with a $100.0 million senior unsecured loan. The loan will be repaid in 15 semi-annual payments of $4.2 million each, commencing on September 15, 2021, with a final payment of $37 million on March 15, 2029. The average duration of the loan is 7 years. The loan bears interest at a fixed rate of 4.8% per annum, payable semi-annually, subject to adjustments in certain cases.

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.

Table of Contents

How We Explore and Evaluate Geothermal Resources

Since 2006, we have expanded our exploration activities, initially in the United States and in the last few years with an increasing focus internationally. It generally 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

We identify and evaluate 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

We acquire land rights to any geothermal resources our initial evaluation indicates could potentially support a commercially viable power plant. 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. The BLM and the Minerals Management Service regulate leasehold interests in federal land in the United States. These agencies have rules governing the geothermal leasing process as discussed below under "Description of Our Leases and Lands".

Table of Contents

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

We conduct geological, geochemical, and/or geophysical surveys on the site we acquire. 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.

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

We drill 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. We only reach such spending levels for sites that proved to be successful in the early stages of exploration.

Table of Contents

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 has taken us two to 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 $8.5 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.

Table of Contents

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 2018, in the Electricity segment, we focused on the commencement of operations at McGinness Hills phase 3 in Nevada and at the Olkaria III plant expansion in Kenya. We began with construction of Steamboat Hills enhancement and Tungsten Solar in Nevada as well as with enhancement work in some of our operating power plants. During fiscal year 2017, 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.

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 2018 we decided to discontinue our holding in the lease at one prospective site: Ruby Valley in Nevada. 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.

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”).

We added to our exploration inventory six prospective sites in 2018 two prospective sites in 2017 and 10 prospective sites in the year ended 2016.

How We Operate and Maintain Our Power Plants

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 include 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.

Table of Contents

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., our purchasers are either state-owned utilities or a privately-owned-entities and we typically operate our facilities under 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".

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. 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 Tungsten, and an operating lease arrangement for our Puna complex power plants.

We have also used a sale of equity interests in three 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 some of the same financing structures 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".

Table of Contents

Description of Our Leases and Lands

We have domestic leases on approximately 365,988 acres of federal, state, and private land in California, Hawaii, Nevada, New Mexico, Utah Idaho and Oregon. The approximate breakdown between federal, state and private leases and owned land is as follows:

- 80% of the acreage under our control is leased from the U.S. government, acting mainly through the BLM;
- 16% is leased or subleased from private landowners and/or leaseholders;
- 3% is owned by us; and
- 1% is leased from various states.

Each of the leases within each of the categories above has standard terms and requirements, as summarized below. Internationally, our land position includes approximately 60,903 acres.

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. Since 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, including use, off-road vehicles, and/or wind or solar energy developments.

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 lessee is drilling a well for the purposes of commercial production, the lease may be extended for five years and thereafter as long as steam is being produced and used in commercial quantities the lease may be extended for up to 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 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.

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.

Table of Contents

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	26 MW
Number of Power Plants	Two (Brady and Desert Peak 2 power plants).
Technology	The Brady complex utilizes binary 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	Four OECs 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. In 2018, additional new OEC was added and three old steam turbines and associated systems were decommissioned. 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 266 degrees Fahrenheit and 332 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 four years, the cooling at the Brady power plant has levelled off to a rate of 2.6 degrees 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.

Table of Contents

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	Construction of new OEC was completed and on-line since the first quarter of 2018.

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	37 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 14 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 323 degrees Fahrenheit.

Table of Contents

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	With a new chemical supply system, we plan to activate several idle wells. New production well was drilled and added to the production header in 2018 and as a result, we expect to see an increase in generation.

Don A. Campbell Complex

Location	Mineral County, Nevada
Generating Capacity	39 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
Major 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

The Don A. Campbell area is comprised of BLM leases.

Land and Mineral Rights 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 in leases from BLM.

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 247 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 have been used to develop a plan to mitigate temperature decline of the reservoir. First stages of this plan will occur in Q1 2019.

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 in connection with the tax equity partnership transaction as described below

<u>Heber Complex</u>

Location	Heber, Imperial County, California
Generating Capacity	81 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, a binary bottoming unit called Gould 1, a new high temperature OEC14 that was added in 2018 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 335 degrees Fahrenheit. The resource supplying the pumped Heber 2 wells averages 315 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.

Table of Contents

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, which was closed in 2017, involving our subsidiary ORTP.
Supplemental Information	We are currently in the process of enhancing the Heber 1 and Heber 2 power plants as discussed below.

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 305 degrees Fahrenheit.

Table of Contents

Resource Cooling	Cooling is stable at 3 degrees Fahrenheit per year following 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.
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.

The average resource temperature is 334 degrees Fahrenheit.

Resource Information

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	Over the last four years temperature decline is less than 0.5 degrees Fahrenheit per year.
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	140 MW
Number of Power Plants	Three (first, second and third phases)
Technology	The McGinness Hills complex utilizes an air cooled binary system.
Subsurface Improvements	15 production wells and nine injection wells are connected to the power plant.
Major Equipment	Nine air cooled OECs with the Balance of Plant equipment.
Age	The first phase power plant commenced commercial operation on July 1, 2012, the second phase power plant commenced commercial operation on February 1, 2015, and the third phase power plant commenced operation on December 15, 2018.
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".
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 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.
Power Purchaser	Nevada Power Company and SCPPA.
PPA Expiration Date	First and second phases – 2033 and third phase – 2043.

Table of Contents

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.

Neal Hot Springs Plant

Location	Malheur County, Oregon.
Generating Capacity	22 MW
Number of Power Plants	One power plant consisting of three modules
Technology	The Neal Hot Springs project utilizes binary, air cooled systems. The heat exchanger uses R-134a fluid
Subsurface Improvements	The project has four production wells and nine injection wells (four are in use).
Major Equipment	Atlas Copco turbine, Lufkin gearbox, Ohmestead vaporizers, Ruhrpumpen feed pump Hyundai generator and Hudson ACC.
Age	The Neal Hot Springs project operation date was November 16, 2012.
Land and Mineral Rights	The Company holds 3 lease contracts for approximately 7,429 acres of geothermal water rights located in the Neal Hot Springs area near Vale, Oregon. The contracts have stated terms of 10 years with expiration dates that range from May 2015 to November 2019. Approximately 521 acres of geothermal rights at Neal Hot Springs are owned by Cyprus Gold Exploration Corporation (50%), JR Land and Livestock (25%), and USG Oregon LLC (25%). Royalty for the two private leases is paid on the gross revenue from energy sales paid by Idaho Power Company under the PPA. The JR Land & Livestock lease has a 3% royalty for the first five years of production, increases to 4% for years 6-15, and then to 5% for the remainder of the lease term. The Cyprus lease establishes a 2% royalty for the first ten years and then escalates to 3% for the remainder of the lease.

The Neal Hot Springs project has four primary permits governing power plant operations. The permits include:

1. Geothermal Well Permits issued by the Department of Geology.

2. A Right-of-Way issued by the Bureau of Land Management.

3. A Conditional Use Permit issued by the Malheur County Commission

4. Underground Injection Control Permit issued by the Oregon Department of Environmental Quality.

Access to Property	Direct access to the plant from public roads. Access across the leased property are provided pursuant to the leases.
	The Neal Hot Springs geothermal system is located near Vale, Oregon, in Malheur County.
Resource Information	Well depths are between 2,500 and 3,000 feet. As of 12/31/18, production well temperatures ranged between 280- and 285-degrees Fahrenheit. As of 12/31/18, the average brine inlet temperature was 283 degrees Fahrenheit.
Resource Cooling	Average brine inlet temperatures declined 1.3 degrees Fahrenheit over the past year.
Power Purchaser	Idaho Power Company.

PPA Expiration Date	March 1, 2038.
Financing	Department of Energy senior secured loan.
Supplemental Information	The Neal Hot Spring power plant was acquired as part of USG acquisition in April 2018. Enbridge Inc. holds ownership interest of 40% effective January 1, 2013.

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 Power Plants	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
	2031

PPA Expiration Date	
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. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants.

<u>OREG 2 Power Plant</u>

Location	Four gas compressor stations along the Northern Border natural gas pipeline in one in Montana, two in North Dakota, and one in Minnesota.
Generating Capacity	22 MW
Number of Power Plants	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. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants.

Table of Contents

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 Power Plants	One
Technology	The OREG 3 power plant utilizes our air cooled OECs.
Major Equipment	One WHOH and one OECs together 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. ORPD owns the Puna complex, the Don A. Campbell phase 1 power plant, and the OREG 1, OREG 2, and OREG 3 power plants.

OREG 4 Power Plant

Location	A gas compressor station along natural gas pipeline in Denver, Colorado.
Generating Capacity	3.5 MW
Number of Power Plants	One
Technology	The OREG 3 power plant utilizes our air cooled OECs.
Major Equipment	Two WHOH and one OECs together with the Balance of Plant equipment.
Age	The OREG 4 power plant commenced commercial operations 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.

Table of Contents

Ormesa Complex

Location	East Mesa, Imperial County, California
Generating Capacity	39 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.
Major Equipment	8 OECs and one steam turbines with the Balance of Plant equipment.
Age	The various OG I power 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 278 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

Resource Cooling	Temperature decline is less than one degree Fahrenheit per year.
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 Ormesa 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.

We are currently in the process of replacing old equipment with new technology equipment.

Table of Contents

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 were connected to the plants through a gathering system prior to May 1st, 2018 volcano eruption. Two production and one injection well were covered by lava, but these were some of the least contributors.
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.

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 that have been postulated to exist along the axis of the rift at depths below 7,000 feet.

Resource Information

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 was stable prior to the volcano eruption. The shut- down of the power plant resulted in some increase in temperature, and reservoir studies are underway to quantify any changes.

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.

Table of Contents

Supplemental Information	On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. The power plant was shutdown immediately and has not been in operation since then. Following the lava stop we are working to bring the power plant back to operation, as discussed under “Recent Developments”.

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 that the price for energy delivered during on-peak hours shall 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:

For the first off-peak 5 MW, a flat rate of 11.8 cents per kWh escalating by 1.5% per year.

For the energy above 27 MW and up to 38 MW, six 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

Raft River

Location	Near the town of Malta, Idaho
Generating Capacity	11 MW
Number of Power Plants	One.
Technology	The project utilizes binary, water-cooled systems. The heat exchanger uses Isopentane.
Subsurface Improvements	Five production wells and four injection wells are connected to the plant.
Major Equipment	The plant consists of one OEC along with the Balance of Plant equipment.
Age	The Raft River Energy I power plant achieved commercial operation on January 3, 2008.
Land and Mineral Rights	The project has 10.8 square miles under lease. The plant has a footprint of 3.5 acres. The project also has 8 private geothermal leases, one of which is owned by the parent company. The parent company retains direct control over 4 private leases and one federal lease outside the Raft River Energy position.

The federal lease was established in August 2007 with a primary term of 10 years and automatic renewal thereafter.

Table of Contents

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 Raft River Energy I geothermal system is located in Southern Idaho, approximately 12 miles south of Malta. Well depths are between 4,500 and 6,000 feet. The production well temperatures ranges between 250 to 302 degrees Fahrenheit. The average brine inlet temperature is 270 degrees Fahrenheit.
Resource Cooling	In 2018, the average brine inlet temperature increased 0.6 degrees Fahrenheit.
Power Purchaser	Idaho Power Company.
PPA Expiration Date	2032
Financing	Loan from Prudential capital Group.
Supplemental information	The Raft River power plant was acquired as part of USG acquisition in April 2018.

San Emidio

Location	Near the town of Gerlach, Nevada
Generating Capacity	11 MW
Number of Power Plants	One
Technology	The project utilizes a binary, water-cooled system. The heat exchanger uses R-134a fluid.
Subsurface Improvements	Four production wells (3 are used) and four injection wells (3 used) are connected to the plant.

Major Equipment	Atlas Copco, Lufkin gearbox, Ohmstede vaporizer, Ruhrpumpen feed pump, BosHaten condensers, Evaptech Cooling tower and Hyundai generator.
Age	The San Emidio power plant commenced commercial operation on May 25, 2012.
Land and Mineral Rights	The resource under lease is 27.9 square miles. The power plant footprint is 2.6 acres. Land ownership consists of 57.7% private property and 42.3% federally managed land. Per federal regulations applicable for the contracts, the lessee has the option to extend the primary lease term another 40 years if the BLM does not need the land for any other purpose and the lessee is maintaining production at commercial quantities. The leases require the lessee to conduct operations in a manner that minimizes adverse impacts to the environment. The project has a lease agreement with Kosmos Company, which requires royalty payments of 1.65% on gross electricity sales for the first 120 months and 3.5% royalty for the remaining term.
	The San Emidio project has five primary permits governing power plant operations.
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.

Table of Contents

Resource Information	The San Emidio geothermal system is located approximately 100 miles northeast of Reno, Nevada and approximately 14 miles south of the town of Gerlach. Well depths are between 1,500 and 3,000 feet. As of 12/31/18, production well temperatures ranged between 262 to 289 degrees Fahrenheit. The average brine inlet temperature is 275 degrees Fahrenheit.
Resource Cooling	During 2018, the average brine inlet temperature declined 3 degrees.
Power Purchaser	NV Energy.
PPA Expiration Date	2038.
Financing	A long-term note held by Prudential Financial Group.
Supplemental information	The San Emidio power plant was acquired as part of USG acquisition in April 2018.

Steamboat Complex

Location	Steamboat, Washoe County, Nevada
Generating Capacity	65 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.

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.
	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.
Land and Mineral Rights	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.
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 at the lower area averages 270 degrees Fahrenheit. The resource at Steamboat Hills averages 326 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.

Table of Contents

	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 between 2°F to 3°F per year.
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) and Galena 3), Nevada Power Company (for Galena 2 until February 28, 2019) and SCPPA (for Steamboat Hills and Galena 2 on March 1st, 2019).
PPA Expiration Date	Steamboat 2 and 3 — 2022, Burdette (Galena1) — 2026, Steamboat Hills — 2043, Galena 3 — 2028, and Galena 2 — Nevada Power Company 2019 and SCPPA 2043.
Financing	Financings were fully paid.
Supplemental information	In Steamboat Hills we are replacing all the equipment and expect to add to the existing projects more than 16MW. See below “Steamboat Hills Enhancement”.

Tungsten Mountain (U.S.)

Location	Churchill County, Nevada.
Generating Capacity	27 MW
Number of Power Plants	One

Technology	The Tungsten Mountain power plant utilizes an air cooled binary system.
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.
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 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 289 degrees Fahrenheit with measured high permeability.
Resource Cooling	Temperature decline is one-degree Fahrenheit per year.
Power Purchaser	SCPPA.
PPA Expiration Date	2043
Financing	Proceeds from the Tungsten tax equity partnership transaction

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 fourth 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”.
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 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 329 degrees Fahrenheit.
Resource Cooling	We expect gradual decline in the cooling trend from less than three degrees Fahrenheit per year in the next two to three years, to less than one degree Fahrenheit per year over the long term.
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. Cooling water supply continues to curtail production in the summer. During 2019, we plan to replace part of the water cooling systems by air cooling systems to reduce our dependence on the make-up water.

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	Five 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 three percent 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.
Access to Property	The generated electricity is sold at the plant fence. The transmission line is owned by INDE.

	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.
	The resource temperature is an average of 518 degrees Fahrenheit.
Resource Information	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.
Power Purchaser	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.
Supplemental information	During 2019 we plan to improve the gathering system that connect the geothermal wells to the power plant and expect generation to increase by reducing the pipe losses.

Table of Contents

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 turbine 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.
Access to Property	Direct access to site through public roads.
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.
Power Purchaser	EDF pursuant to a PPA.
PPA Expiration Date	December 31, 2030.
Financing	Corporate funds.

Supplemental information	85% of the project is owned jointly by Ormat and CDC allocated 75% to Ormat and 25% to CDC.

Olkaria III Complex (Kenya)

Location	Naivasha, Kenya.
Generating Capacity	150 MW
Number of Power Plants	Four (Plant 1 with the addition of new 11MW OEC), 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. Decommissioned OEC1 and added OEC7 to plant 1 in 2018.
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.

53

Table of Contents

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.
	The average resource temperature is 570 degrees Fahrenheit.
Resource Information	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.
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	In June 2018, we successfully commenced commercial operation of the 11 MW Plant 1 expansion, which increased the Complex capacity to 150 MW.

Platanares (Honduras)

Location	Copan, Honduras
Generating Capacity	38 MW
Number of Power Plants	One

Technology	The Platanares power plant utilizes an air cooled binary system.
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.

Table of Contents

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.
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 meter deep. Production temperature is 350 degrees Fahrenheit with high productivity.
Resource Cooling	The cooling approximately 2 degrees Fahrenheit per year.
Power Purchaser	ENEE pursuant to a PPA.
PPA Expiration Date	2047
Financing	Secured project finance loan from OPIC.
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.

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 hold a 12.75% interest.
Generating Capacity	Currently three phases (SIL and NIL 1&2) are operating with a total capacity of approximately 330 MW (Ormat's ownership share is approximately 42MW). Ormat's own

	equipment is producing approximately 40% of the power.
Number of Power Plants	Three (SIL and NIL 1 & 2)
Technology	Integrated Geothermal Combined Cycle Unit comprised of one back pressure steam turbine and six OECs for each phase (together three steam turbines and 18 OECs.
Subsurface Improvements	15 production wells and 20 injection wells are connected to the plant through a gathering system.
Major Equipment	Three back pressure steam turbines and 18 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 commenced commercial operation in March 2017, NIL 1 power plant in October 2017, and NIL 2 in April 2018.
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.

Access to Property	Access to property for the project has been secured.
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 20MW electrical production.
Resource Cooling	Since the project commenced operation the resource temperature has been stable.
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.

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 Improvements	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 commanced 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.
Access to Property	Direct access to public roads.
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 2,860-4,300 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.

Table of Contents

Resource Cooling	The resource temperature is stable.
Power Purchaser	ENDE
PPA Expiration Date	2034
Financing	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 17 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.

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

Capacity payment:

o Until 2019, the capacity payment will be calculated based on a 24 MW generating capacity regardless of the actual performance of the power plant.

o From 2019 and thereafter, the capacity payment will be based on actual delivered capacity and the capacity rate will be reduced.

Energy payment:

o 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.

- 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 two projects that are in initial stages of construction.

Table of Contents

The following is a description of projects in the U.S. that were released for, and are in different stages of, construction. These projects are expected to have a total generating capacity of 37 MW (representing our interest).

Heber Complex (U.S.)

Location	Heber, Imperial County, California
Projected Generating Capacity	11 MW
Projected Technology	The power plant will utilize an air cooled binary system
Condition	Construction (engineering is on-going)
Land	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.
Power Purchaser	One PPA with Southern California Edison and one PPA with SCPPA.
PPA Expiration Date	Heber 1 — 2025, Heber 2 — 2023
Financing	Corporate funds
Projected Operation	Early 2021

Supplemental Information	We are currently in the process of repowering the Heber 1 and Heber 2 power plants. We are planning to replace steam turbine and old OEC units with new advanced technology equipment. Following these enhancements, we expect the capacity of the complex to reach 92 MW.

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 a 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	2019
Supplemental Information	We plan to install Solar PV systems in the Tungsten Mountain geothermal power plant to reduce internal (a.k.a 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.

58

Table of Contents

Steamboat Hills Enhancement (U.S.)

Location	Washo County, Nevada
Projected Generating Capacity	19 MW
Projected Technology	The power plant will utilize an air cooled binary system
Condition	Construction (engineering procurement is on-going)
Land	The Steamboat Hills area is comprised private leases, BLM leases and 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.
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.
Power Purchaser	SCPPA
PPA Expiration Date	2043
Financing	Corporate funds
Projected Operation	2020
Supplemental Information	We are replacing all the equipment of this power plant and plan to add to the existing projects more than 16MW

The following is a description of projects in California and Nevada with an expected total generating capacity of 40-45 MW that are in an **initial stage of construction**:

Carson Lake Project (U.S.)

Location	Churchill County, Nevada
Projected Generating Capacity	10MW - 15MW
Projected Technology	The Carson Lake power plant will utilize a binary system.
Condition	Initial stage of construction.
Land	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 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 leases are extended for 35 years with the possibility of additional extension of 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.

Table of Contents

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	End of 2021
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	30 MW
Projected Technology	The CD4 power plant will utilize an air cooled binary system.
	Initial stage of construction.
Condition	We have completed two production wells, one of which was previously considered as an injection well. In 2017 we drilled a core well to begin baseline monitoring, as required by our permit. Continued drilling is planned for 2019.
Land	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	Subject to PPA execution.
Supplemental Information	We signed a Wholesale Distribution Access Tariff Cluster Large Generator Interconnection Agreement with SCE in December 2017. PPA is under negotiation,

Future Projects

Projects under Various Stages of Development

We also have projects under various stages of development in the U.S., and Guadeloupe. 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 90 MW to 105 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 2019.

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 2021, subject to PPA execution.

Dixie Meadows

We are currently developing the 10 MW to 15 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. We expect this project to be completed in 2021.

North Valley

We are planning to develop a 30 MW to 40 MW geothermal project adjacent to the San Emidio project in Nevada. The project is expected to sell its electricity under the Portfolio SCPPA PPA. We expect the project to be completed by the end of 2021.

Tungsten Phase 2

We are planning to develop a 15 MW geothermal project that will be added to the current operating Tungsten power plant in Nevada. The project is expected to sell its electricity under the Portfolio SCPPA PPA. We expect the project to be completed by the end of 2020.

Wister Solar

We are planning to develop a 20 MW Solar PV project on the Wister site in California. We plan to install Solar PV systems and sell the electricity under a PPA with San Diego Gas & Electric. We expect the project to be completed by the end of 2020.

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.

During fiscal year 2018, we discontinued holding a lease at one prospect at Ruby Valley, Nevada. We added six new prospects in 2018, in the U.S. and Indonesia.

Our current land position is comprised of various leases, concessions and private land for geothermal resources of approximately 248,680 acres in 38 prospects including the following:

Nevada (18)

1.	Alum	Exploration studies in progress;
2.	Baltazor	Under exploration drilling;
3.	Colado	Under exploration drilling;
4.	Crescent Valley	Under exploration drilling;
5.	Dixie Comstock	Exploration studies in progress;
6.	Edwards Creek	Under exploration drilling;
7.	Gerlach	Under exploration drilling;

61

Table of Contents

8.	Horsehaven (formerly Beowawe)	Exploration studies in progress;
9.	Lee Hot Springs	Exploration studies in progress;
10.	North Valley	Exploration studies in progress;
11.	North Valley 2	Exploration studies in progress;
12.	New York Canyon	Exploration studies in progress;
13.	Pearl Hot Springs	Exploration studies in progress;
14.	Rhodes Marsh	Exploration studies in progress;
15.	South Brady	Exploration studies in progress;
16.	Trinity	Exploration studies in progress;
17.	Tungsten Mountain – Phase 2	Assessment for future expansion; and
18.	Twin Buttes	Lease acquired but no further action has been taken yet.

California (4)

1.	Glamis	Exploration studies in progress;
2.	Geysers	Under exploration drilling;
3.	Rhyolite Plateau	Exploration studies in progress; and
4.	Truckhaven	Exploration studies in progress.

Oregon (3)

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

New Mexico (1)

1.	Rincon	Exploration studies in progress.

Utah (2)

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

Guatemala (2)

1. Amatitlan Phase II Exploration studies in progress; and
2. Tecumburu Exploration studies in progress.

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.

Indonesia (1)

1. Bitung Exploration studies in progress.

Table of Contents

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 own and operate as well as working to develop energy storage projects in the United States including the following:

Under operation

ACUA

Location	NJ
Size	1MW/1MWh
RTO/ISO	PJM
Owner	Ormat
Key Services provided	• Frequency Regulation • Peak Shaving / PLC Management • ACUA obtains annual lease payment for energy storage on their site for 10 years • ACUA gains additional reliability and power quality • ACUA gains demand charge savings on a shared basis
Status	In commercial operation since Q2 2018

Stryker

Location	NJ
Size	20MW/20MWh
RTO/ISO	PJM
Owner	Ormat
Key Services provided	• Frequency Regulation • Capacity • Reactive Power
Status	In commercial operation since Q1 2019

Plumstead

Location	NJ
Size	20MW/20MWh
RTO/ISO	PJM
Owner	Ormat
Key Services provided	• Frequency Regulation • Capacity • Reactive Power
Status	In commercial operation since Q1 2019

Under construction and development

<u>Rabitt Hills</u>

Location	Georgetown, Texas
Size	10MW/12.5MWh
RTO/ISO	ERCOT
Owner	Ormat
Key Services provided	• Frequency Regulation • Load Shifting
Status	Under construction – COD is expected in 2019

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. We also provide the purchaser with spare parts (either upon their request or our recommendation). We provide the purchaser with at least a 12-month warranty for such products. We provide the purchaser with performance guarantees (usually in the form of standby letters of credit), which partially terminates upon delivery of the equipment to the site and terminates in full at the end of the warranty period.

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 manufacture 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 that our advantage is in 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 provide performance guarantees (usually in the form of standby letters of credit) securing our obligations under the contract.

Table of Contents

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 $216.8 million as of February 26, 2019, which includes revenues for the period between January 1, 2019 and February 26, 2019, compared to $243.0 million as of February 26, 2018, which included revenues for the period between January 1, 2018 and February 26, 2018.

The following is a breakdown of the Product segment backlog as of February 26, 2019 ($ in millions):

	% of Total Backlog	Latest Expected Completion
Geothermal	96.5%	2020
Recovered Energy	0	
Other	3.5%	2019

Competition

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

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

Table of Contents

Our main competitors in the geothermal sector in the United States are CalEnergy, Calpine Corporation, Terra-Gen Power LLC, Enel Green Power S.p.A., Cyrq Energy Inc. 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 hydroelectric power. Increasingly we compete against these technologies combined with energy storage. In the last few years, competition from the wind and solar power generation developers 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.

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.

Our low enthalpy competitors are binary systems manufacturers using the ORC 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. In addition in 2018 was Kaishan, a compressor manufacturer from China who develops its own projects. 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 82%), an increase in competition, which we are currently experiencing, has started to affect 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 ORC 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 competes 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.

Other Segment

In the demand response markets, our Viridity business competes primarily with specialized demand management providers and 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 independent power producers, project developers, system integrators, EPC providers, hardware suppliers (e.g. batteries, inverters, and balance of plant), scheduling coordinators, software suppliers, etc. Our proprietary software, analytical operational platform and experience in storage operation and integration with electricity markets, as well as our engineering capabilities, 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.

Table of Contents

Customers

All of our revenues from the sale of Electricity in the year ended December 31, 2018 were derived from fully-contracted energy and/or capacity payments under long-term PPAs with governmental or private utility entities. The percentage of total revenues above 5% is detailed in the table below:

Utility	% of total revenues for the year ended December 31, 2018	
NV Energy	16.1%	
HELCO	2.2%	(lower than 5% due to the volcanic eruption)
SCPPA	15.2%	
KPLC	16.6%	

Based on publicly available information, as of December 31, 2018, the credit ratings of our rated electric utilities are as set forth below:

Issuer	Standard & Poor's Ratings Services	Moody's Investors Service Inc.
Southern California Edison	BBB+ (Negative)	A3 (Rating Affirmation)
HELCO	BBB- (Stable)	Baa2
Sierra Pacific Power Company	A (Stable)	Baa1 (Rating Affirmation)
Nevada Power Company	A (Stable)	Baa1 (Rating Affirmation)
SCPPA	BBB+ (Stable)	Aa2 (Stable)
PG&E	D (NM)	Caa3(Negative)
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.

Pacific Gas & Electric which accounted for approx. 1.9% of our total revenues for fiscal year ended 2018, is facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. If Pacific Gas & Electric is found liable for the wildfires, its potential liabilities could exceed $30B. As a result, on January 29, 2019, Pacific Gas & Electric filed for reorganization under Chapter 11 bankruptcy. The Company is closely monitoring its Pacific Gas & Electric account to ensure cash receipts are received timely each month.

However, we cannot estimate at this stage the impact that may have on us as a result of the Chapter 11.

We have historically been able to collect on substantially all of our receivable balances. Recently, we have received late payments from KPLC in Kenya related to our Olkaria Complex and from ENEE in Honduras related to our Platanares power plant. No provision for doubtful accounts has been recorded since we believe we will be able to collect all past due amounts.

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

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, 2018, we employed 1,346 employees, of which 584 were located in the U.S., 556 were located in Israel and 206 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, 2018, 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.

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, general liability, primary and excess liability insurance, control of wells, drilling rig, 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. To the extent any such casualty insurance covers the Company and/or any owned controlled, direct or indirect affiliated or associated company, subsidiary company or corporation in an amount based upon the estimated replacement value and maximum foreseeable loss 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. As an exception, at this stage we have not secured physical damage and business interruption coverage for our Puna power plant in Hawaii. Since the volcano eruption in May 2018 we are working to seek such coverage as soon as it becomes available.

We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries. We hold a global political risk insurance program for two to 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.

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.

Table of Contents

PURPA

PURPA and FERC's regulations thereunder 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.

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, geothermal, or 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 been certified as a Qualifying Facility by FERC. 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 not later than December 31, 1994, and construction of the facility commenced not later than December 31, 1999.

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 or (b) not pursuant to 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 on or before March 17, 2006 or pursuant to a state regulatory authority's implementation of PURPA.

In addition, provided that the purchasing electric utility has not been relieved from its mandatory purchase obligation, PURPA and FERC's regulations under PURPA obligate electric utilities to purchase energy and capacity from Qualifying Facilities at either the electric utility's avoided cost or a negotiated rate. FERC's regulations under PURPA 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: (i) independently administered, auction-based day ahead, and real time markets for electric energy and wholesale markets for long-term sales of capacity and electric energy; (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, including long-term and short-term sales, and electric energy, including long-term, short-term, and real-time sales, to buyers other than the utility to which the Qualifying Facility is interconnected; or (iii) wholesale markets for the sale of capacity and electric 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. FERC is re-evaluating aspects of its PURPA regulations, including the 20 MW threshold.

We expect that our power plants in the U.S will continue to meet all of the criteria required for Qualifying Facility status 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 a waiver of the mandatory purchase obligation is obtained, 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.

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 can accept, reject or suspend rates. The rates can be suspended for up to five months, at which point the rates become effective subject to refund. FERC can order refunds for rates that are found to be "unjust and unreasonable" or "unduly discriminatory or preferential."

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 indenture for 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.

Additionally, FERC possesses civil penalty authority, up to approximately $1.2M per violation of the FPA per day. FERC can also require the disgorgement of unjust profits earned in connection with such violations of the FPA and revoke the right of the power plants to make sales at market-based rates.

Under the Energy Policy Act of 2005, the FPA was supplemented to empower FERC to ensure the reliability of the bulk electric system. Such authority required that FERC assume both oversight and enforcement roles. Pursuant to its new directive, FERC certified the North American Electric Reliability Corporation as the nation's Electric Reliability Organization (ERO) to develop and enforce mandatory reliability standards to address medium and long-term reliability concerns. Today, enforcement of the mandatory reliability standards, including the protection of critical energy infrastructure, is a substantial function of the ERO and of FERC, which may impose penalties of up to approximately US$1.2 million a day for violating mandatory reliability standards.

Thus, if any of the power plants were to lose Qualifying Facility status, the application of the FPA and other applicable state regulations to such power plants could require compliance 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, the owner of a Qualifying Facility/power plant in excess of 20 MW will become subject to rate regulation under the FPA for sales of energy or capacity pursuant to a contract executed after March 17, 2006 or not pursuant to a state regulatory authority's implementation of PURPA. A decrease in existing rates or being ordered by FERC to pay refunds for rates found to be "unjust and unreasonable" or "unduly discriminatory or preferential" would likely result in a decrease in our future revenues.

State Regulation

Our power plants in California, Nevada, Oregon, and Idaho, 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, SCPPA and Idaho Power Company). 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.

Table of Contents

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 United States 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, on BLM lands in Nevada, California, Oregon, and Idaho, 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 UIC permits from the Nevada Division of Environmental Protection and Bureau of Water Pollution Control. All geothermal wells drilled in Oregon require a geothermal well drilling permit from the Oregon Department of Geology and Mineral Industries. All geothermal wells drilled in Idaho require a well construction permit from the IDWR and injection wells also require UIC permitting through IDWR. 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 Nevada, California, Oregon, and Idaho, 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 that 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.

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.

Table of Contents

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.

Regulation Related to New Activity

Our recent entry into the energy storage space and planned provision of energy management and demand response require us to obtain and maintain certain additional authorizations and approvals. These include (1) authorization from FERC to make wholesale sales of energy, capacity, and ancillary services at market-based rates, and (2) membership status with eligibility to serve designated contractual functions in the ISO/RTOs of PJM, NYISO, and ERCOT. In the future, we may need to obtain and maintain similar membership and eligibility status with other ISO/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 that 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 major licensed public electricity supplier and has a virtual monopoly in the distribution of electricity in the country with the exception of a few off-grid, which have recently been licensed by the ERC. 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. Renewable energy (principally solar, wind and biomass) is now one of the key energy sub-sectors in Kenya contributing significantly to the overall energy mix as a result of the implementation of the feed-in- tariff policy by the Ministry of Energy. Under the 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).

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

ITEM 1A. RISK FACTORS

The following risk factors should be read carefully in connection with evaluating us and this Annual Report on Form 10-K. Certain statements in "Risk Factor" are forward-looking statements. See "Cautionary Note Regarding Forward-Looking Statements" elsewhere in the report:

Risks Related to the Company's Business and Operation

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

Our financial performance depends on the successful operation of our geothermal and REG power plants. In connection with such operations, we derived 70.9% of our total revenues for the year ended December 31, 2018 from the sale of electricity. The cost of operation and maintenance and the operating performance of our geothermal power and REG plants may be adversely affected by a variety of factors, including 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, such as the recent volcanic eruption that occurred in Hawaii's Big Island that impacted our Puna project, as discussed elsewhere in this Report; 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 flows.

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. 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.

Table of Contents

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. Costs 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 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. Also, volcanic eruptions and lava flows may happen in Hawaii, Guatemala and Indonesia. 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.

On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. Before it recently stopped flowing, the lava covered the wellheads of three geothermal wells, monitoring wells and the substation of the Puna complex and an adjacent warehouse that stored a drilling rig that was also consumed by the lava. The insurance policy coverage for property and business interruption is provided by a consortium of insurers. All the insurers accepted and started paying for the costs to rebuild the destroyed substation, and as of December 31, 2018 we received $3.3 million. However only some of the insurers accepted that the business interruption coverage started in May 2018 and as of December 31, 2018 we recorded $12.1 million of such proceeds. We are still in discussions to reach an understanding with all insurers to start paying for the business interruption as of May 2018. The Company is still assessing the damages in the Puna facilities and continue to coordinate with HELCO and local authorities to bring the power plant back to operation. The Company continues to assess the accounting implications of this event on the assets and liabilities on its balance sheet and whether an impairment will be required. Any significant physical damage to the geothermal resource or continued shut-down following the recent stop of the lava of the Puna facilities could have an adverse impact on the power plant's electricity generation and availability, which in turn could have a material adverse impact on our business and results of operations.

In addition to our power plant in Puna, Hawaii, our power plant in Amatitlan, Guatemala is located in proximity to an active volcano. As a result of recent events impacting our Puna facility, we cannot be certain how investors will assess the risks to which our facilities are subject and whether this assessment will adversely impact perceptions of our business and our share price.

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 power plant.

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 of enhancing shareholder value through long-term growth of the Company

We adopted a multi-year strategic plan to:

- expand our geographic 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.

Table of Contents

There are uncertainties and risks associated with the plan, both as to implementation and outcome. We may decide to change, or to not implement, one or more elements of the plan over time or 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 are unknown to us now that will impact these markets;

- our ability to devote the amount of management time and other resources required to implement this plan, while 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.

Implementing the plan may also 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.

Apart from the risks associated with implementing the plan, the plan itself will expose us to other risks and uncertainties once implemented. Expanding our customer base may expose us to different credit profile customers than our current customers. 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. In addition, expanding into new technologies will expose us to new risks and uncertainties that are unknown to us now in addition to the risks and uncertainties that may be similar to those we now face. 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 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.

Concentration of customers and regions may expose us to heightened financial exposure.

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 a long-term agreement between the parties. A facility’s financial results could be materially and adversely affected if any of our customers fail to fulfill its contractual obligations and we are unable to find other customers to purchase at the same level of profitability. We cannot assure that such performance failures by our customers will not occur, or that if they do occur, such failures will not adversely affect the cash flows or profitability of our businesses.

Table of Contents

For example, in the Electricity segment, we are exposed to the credit and financial condition of KPLC that buy the power generated from our Olkaria III in Kenya. In 2018, KPLC accounted for 16.6% of our total revenues. Any change in KPLC's financial condition may adversely affect us. Another example, we are exposed to the credit and financial condition of SCPPA and its municipal utility members that account for 15.2% of our total revenues, as customers that buy the output from seven of our geothermal power plants. 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.

Another example, Pacific Gas & Electric who accounted for approximately 1.9% of our total revenues, is facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. If Pacific Gas & Electric is found liable for the wildfires, its potential liabilities could exceed $30B. As a result, on January 29, 2019, Pacific Gas & Electric filed for reorganization under Chapter 11 bankruptcy. We are closely monitoring our Pacific Gas & Electric account to ensure cash receipts are received timely each month. However, we cannot estimate at this stage the impact that this Chapter 11 reorganization may have on us.

In the Product segment, 23.5% and 83.6% of our 2018 total revenues and Products segment revenue, respectively, derived from our operation in Turkey and we rely on the continued geothermal development growth and government support for geothermal development in the country. Our revenue exposure to the Turkish market increased in 2018 and expects to remain significant in 2019, as we signed a number of new contracts in Turkey. Adverse political developments in the relationship between Turkey and the U.S., adverse economic developments in this region including the latest failed coup, devaluation of the Turkish Lira, a general slowdown in the Turkish economy and an inability to obtain project and bank financing 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.

Ormat established a facility in Turkey in order to locally produce several power plant components that entitle our customer for 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

Our international operations expose us to risks related to the application of foreign laws and regulations, any of which may adversely affect our business, financial condition, future results and cash flows.

Our foreign operations in Kenya, Turkey, Guadeloupe, Guatemala, Honduras and other countries 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. The systems of some of these countries can be characterized by:

- selective or inconsistent enforcement of laws or regulations, sometimes in ways that have been perceived as being motivated by political or financial considerations;
- a perceived lack of judicial and prosecutorial independence from political, social and commercial forces;
- a high degree of discretion on the part of the judiciary and governmental authorities;
- legal and bureaucratic obstacles and corruption; and
- rapid evolution of legal systems in ways that may not always coincide with market developments.

These characteristics give rise to investment risks that do not exist in countries with more established legal systems in more developed economies.

Table of Contents

We face additional risks inherent in conducting business internationally, including compliance with laws and regulations of many jurisdictions that apply to our international operations. These laws and regulations include data privacy requirements, labor relations laws, tax laws, competition regulations, import and trade restrictions, economic sanctions, export requirements, the Foreign Corrupt Practices Act, and other local laws that prohibit corrupt payments to governmental officials or certain payments or remunerations to customers. Given the high level of complexity of these laws, there is a risk that some provisions may be breached by us, for example through fraudulent or negligent behavior of individual employees (or third parties acting on our behalf), our failure to comply with certain formal documentation requirements, or otherwise. Violations of these laws and regulations could result in fines, criminal sanctions against us, our officers or our employees, requirements to obtain export licenses, cessation of business activities in sanctioned countries, implementation of compliance programs and prohibitions on the conduct of our business. Any such violation could include prohibitions on our ability to offer our products in one or more countries and could materially damage our reputation, our brand, our ability to attract and retain employees, our business, our financial condition and our results of 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.

Political and economic conditions in the emerging economies where we operate may subject us to greater risk than in the developed U.S. economy, which may have a materially adverse effect on our business.

We have substantial operations outside of the U.S., both in our Electricity segment and our Product segment. In 2018, 54% of our total revenues were derived from international operations, and our international operations were significantly more profitable than our U.S. operations. A substantial portion of international revenues came from Kenya and Turkey and, to a lesser extent, from Guadeloupe, Guatemala and Honduras and other countries. Thus, disturbances to and challenges facing our foreign operations, especially in Kenya and Turkey, could have impacts on our business ranging from moderate to severe. Our foreign operations subject us 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;
-

- the adoption or expansion of trade restrictions, the occurrence or escalation of a "trade war," or other governmental action related to tariffs or trade agreements or policies among the governments of the United States and countries where we operate;
- changes in labor relations;
- political instability and civil unrest, and risk of war;
- changes in the local electricity and/or geothermal markets;
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations;
- breach or repudiation of important contractual undertakings by governmental entities; and
- expropriation and confiscation of assets and facilities, including without adequate compensation.

Electricity Segment. In 2018, the international operations of the Electricity segment accounted for 28% of our revenues, but accounted for 53% of our gross profit, 77% of our net income and 53% of our EBITDA. A substantial portion of Electricity segment international revenues came from Kenya (which also contributed disproportionately to our gross profit and net income) and, to a lesser extent, from Guadeloupe, Guatemala and Honduras. 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 and our overall results of operations. Additionally, 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.

Product Segment. With respect to our Product segment, 93% of our Product segment revenues in 2018 came from international sales, primarily Turkey. 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.

Generally. Outbreaks of civil and political unrest and acts of terrorism have also occurred in several countries in Africa, the Middle East and Latin America, where we have significant operations, such as Kenya and Turkey. For instance, Kenya experienced numerous terrorist attacks in 2014 and 2015, and has experienced an upsurge in attacks in more recent years, including in early 2019, from extremist groups. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired. 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. Any or all of the changes discussed above could materially and adversely affect our business, financial condition, future results and cash flow.

Table of Contents

Two of our facilities accounts for 26% of our revenues and contribute significantly to our profitability.

Our business relies significantly on the performance of our two largest projects, the McGinness Hills complex in East Nevada and Olkaria III Complex in Kenya, which together account for more than 30% of the total generating capacity of our Electricity segment. These two facilities accounted for 26% of our total revenues for the year ended December 31, 2018. Just over one third of the generating capacity at McGinness Hills reached commercial operation in December 2018 and its contribution to our results may therefore be higher in the future. Any disruption to the operation of these facilities would have a disproportionately adverse effect on our revenues and on our profitability compared to our other facilities.

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 approximately 26 miles from the border with the Gaza Strip. As such, political, economic and security conditions in Israel directly affect our operations.

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.

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 have significant operations globally, including in countries that may be adversely affected by political or economic instability, major hostilities or acts of terrorism, which exposes us to risks and challenges associated with conducting business internationally.

We have substantial operations outside of the U.S., both in our Electricity segment and our Product segment. 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.

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 (approximately 249,000 acres) 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, may 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.

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.

Table of Contents

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 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., as well as in Ethiopia, Guadeloupe, Guatemala, Honduras, Indonesia and New Zealand, 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;

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, of if there is a failure that requires long shutdown for repair, or if curtailment is required due to load and inefficiency system, 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.

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

We have partners in several of our plants and 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 arbitration or litigation;

- 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;

- 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.

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. 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.

Storage projects that we are currently developing or plan to develop in the future may operate as "merchant" facilities without long-term power services 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 own and operate, as well others 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 are exposed to market fluctuations. Without the benefit of long-term services 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.

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 and/or renew long-term 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 panels, 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**.**

We are experiencing intense competition in the energy storage, demand response and energy management markets. Our competitors in the energy storage, demand response and energy management markets include utilities, independent power producers, developers, new start-ups, and third-party investors, who 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.

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 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.

Table of Contents

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.

We previously identified a material weakness in our internal control over financial reporting and subsequently restated certain of our financial statements as a result of factors related to that weakness. This may adversely affect the accuracy and reliability of our financial statements and impact 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 U.S. 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. Our management previously concluded that this deficiency constituted a material weakness in our internal control over financial reporting and, accordingly, our 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.

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 our ability to utilize foreign tax credits in the United States ("U.S.") prior to their expiration starting in 2027 and the resulting impact on the 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, we also concluded that we would revise our previously issued consolidated financial statements as of and for the years ended December 31, 2016 and 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. These tax and tax-related errors 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 months ended March 31, 2017, for the three and six months ended June 30, 2017 and 2016 and for the three and nine months ended September 30, 2017 and 2016.

While we have developed and are in the process of implementing a plan to remediate this material weakness, there can be no assurance that this will occur within 2019. 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 in relation to covenants in certain debt facilities will likely be adversely affected. The occurrence of, or failure to remediate, 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.

Our failure to prepare and timely file our periodic reports with the SEC limits our access to the public markets to raise debt or equity capital.

We did not file our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 within the timeframe required by the SEC, meaning we were not current in our reporting requirements with the SEC. Even though we have regained compliance with our SEC reporting obligations, we will be not be eligible to use a short-form registration statement on Form S-3 that would allow us to incorporate by reference our SEC reports into the registration statement, or to use “shelf” registration statements, until one year from the date we regained and maintain status as a current filer. If we wish to pursue a public offering during this time period, we would be required to file a long-form registration statement on Form S-1 and have it reviewed and declared effective by the SEC. Doing so would likely take significantly longer than using a short-form registration statement on Form S-3, increase transaction costs and adversely impact our ability to raise capital or complete acquisitions of other companies in a timely manner.

Table of Contents

Risks Related to Governmental Regulations, Laws and Taxation

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

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.

Regulations related to conflict minerals, adopted by the SEC and requires us to disclose the use of “conflict minerals” (including tantalum, tin, tungsten and gold) in our products, may force us to incur additional expenses and may damage our relationship with certain customers. 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.

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 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 of the settlement agreements in, 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.

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 may 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.

Table of Contents

The PURPA and QF described risks identified above are not likely to affect our Nevada based facilities that entered into PPAs with NV Energy as the off-taker after Nevada initially adopted its RPS in 2001. Those PPAs and the related rates agreed to for such facilities by the off-taker were not based upon PURPA or a QF mandated rate but were instead adopted as a result of a competitive bidding process and approved as part of the off-taker's integrated resource planning process and in order for the off-taker to comply with Nevada's RPS. While those PPAS were initially required to file for QF or EWG status with the FERC, the PPAs and their related prices for the term of the PPA were not approved by the FERC pursuant to PURPA. The PURPA and QF risks described above also are not likely to affect our Nevada and California based projects that have their PPAs with the SCPPA because SCPPA is not a regulated public utility under PURPA.

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 (that are applicable for projects that started construction by the end of 2017) 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.

We are a holding company and our cash depends substantially on the performance of our subsidiaries and the power plants they operate, most of which is 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 some 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 may also be subject to withholding taxes. Each of the events described above may reduce or eliminate the aggregate amount of cash we can receive from our subsidiaries.

Table of Contents

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.

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.

Table of Contents

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.

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

The recently enacted Tax Act in the U.S. included 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 BEAT is to ensure that multinational companies do not use cross-border payments to reduce their U.S. taxes to less than 10 percent (5 percent for 2018) of an expanded definition of taxable income. BEAT requires an annual calculation. Generally, the tax only applies to certain corporations with at least $500 million in average annual gross receipts for the United States for the three prior taxable years before the calculation and with base erosion payments that account for at least 3 percent (2 percent for certain corporations) of their deductions for the taxable year. 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 Israeli 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.

Risks Related to Economic and Financial Conditions

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.

Table of Contents

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 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.

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.

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.

Risks Related to Force Majeure

The existence of a prolonged force majeure event or a forced outage affecting a power plant, or the transmission systems 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, 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.

Threats of terrorism and catastrophic events that could result from, 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.

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.

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 Act was signed into law, significantly reforming the U.S. Internal Revenue Code. The Tax Act, among other things, reduces the U.S. federal corporate tax rate from the previous top marginal rate of 35% to a flat rate of 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, including the treatment of net operating losses.

Table of Contents

Under the Tax Act, the deductibility of “net interest” for a business is limited to 30% of adjusted taxable income. The new proposed regulations issued by Treasury applies regardless of whether the interest payment is made to a US or foreign person, whether the interest recipient is related, or whether the interest recipient is exempt from US tax. Further, any interest that cannot be deducted in a year can be carried forward indefinitely. The Company has not early adopted these proposed regulations and intends to adopt during the 2019 tax year. For the year ended December 31, 2018, we have evaluated the impact and determined there is no limit on our interest deductibility for federal income tax purposes for the current period, but anticipates there could be significant limitations upon adoption.

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.

Risks Related to Our Stock

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 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;

Table of Contents

- 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, such as the recent class action filed on June 2018 by Mac Costas and discussed elsewhere in this report, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We currently lease corporate offices at 6140 Plumas street Reno, Nevada 89519 to which we moved in the second quarter of 2018. 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 believe that our current offices and 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

The information required with respect to this item can be found under "Commitments and Contingencies" in Note 22 of notes to the consolidated financial statements contained in this annual report and is incorporated by reference into this Item 8.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

94

Table of Contents

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 under the same symbol.

As of February 26, 2019, there were 16 record holders of our common stock. On February 26, 2019, the closing price of our common stock as reported on the NYSE was $56.72 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.

Date Declared	**Dividend Amount per Share**	**Record Date**	**Payment Date**
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

May 7, 2018	$ 0.10	May 21, 2018	May 30, 2018
August 7, 2018	$ 0.10	August 21, 2018	August 29, 2018
November 6, 2018	$ 0.10	November 20, 2018	December 4, 2018
February 26, 2019	$ 0.11	March 14, 2019	March 28, 2019

	First Quarter 2017	**Second Quarter 2017**	**Third Quarter 2017**	**Fourth Quarter 2017**	**First Quarter 2018**	**Second Quarter 2018**	**Third Quarter 2018**	**Fourth Quarter 2018**	**January 1 to February 26, 2019**
High	$ 59.63	$ 61.49	$ 63.56	$ 65.55	$ 70.08	$ 59.8	$ 57.82	$ 56.72	$ 58.0
Low:	$ 51.44	$ 55.73	$ 55.06	$ 60.13	$ 54.22	$ 50.77	$ 49.67	$ 49.51	$ 50.83

95

Table of Contents

Stock Performance Graph

The following performance graph represents the cumulative total shareholder return for the period December 30, 2013 through December 31, 2018 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 December 30, 2013 through December 31, 2018

	2014	**2015**	**2016**	**2017**	**2018**
Ormat Technologies Inc	-0.1 %	34 %	97.1 %	135.1%	92.2 %
Standard & Poor's Composite 500 Index	11.4%	10.6 %	21.1 %	44.6 %	35.6 %
NEX - renewable Index	-0.1 %	-4.0 %	-12.0%	10.7 %	-12.3%
IPP Peers*	4.2 %	89.4 %	67.5 %	62.9 %	72.9 %
Renewable Peers*	34.6%	-35.3%	-29.8%	-10.3 %	4.4 %

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

** Renewable Energy (Renewable) Peers is Acciona S.A.

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”.

Table of Contents

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, 2018, 2017 and 2016 and as of December 31, 2018 and 2017 from our audited consolidated financial statements set forth in Item 8 of this annual report. We have derived the selected consolidated financial data for the years ended December 31, 2015 and 2014 and as of December 31, 2016, 2015 and 2014 from our audited consolidated financial statements not included herein.

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,				
	2018	**2017**	**2016**	**2015**	**2014**
	(Dollars in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity	$509,879	$465,593	$436,292	$375,920	$382,301
Product	201,743	224,483	226,299	218,724	177,223
Other	7,645	2,736	—	—	—
Total revenues	719,267	692,812	662,591	594,644	559,524
Cost of revenues:					
Electricity	298,255	266,840	261,573	242,612	246,630
Product	140,697	152,094	130,223	133,753	109,143
Other	9,880	5,426	—	—	—
Total cost of revenues	448,832	424,360	391,796	376,365	355,773
Gross profit	270,435	268,452	270,795	218,279	203,751
Operating expenses:					
Research and development expenses	4,183	3,157	2,762	1,780	783
Selling and marketing expenses	19,802	15,600	16,424	16,077	15,425
General and administrative expenses	47,750	42,881	46,710	34,782	28,614
Impairment charge	13,464	—	—	—	—
Write-off of unsuccessful exploration activities	126	1,796	3,017	1,579	15,439
Operating Income	185,110	205,018	201,882	164,061	143,490
Other income (expense):					
Interest income	974	988	971	297	312
Interest expense, net	(70,924)	(54,142)	(67,389)	(72,577)	(84,654)
Derivatives and foreign currency transaction gains (losses)	(4,761)	2,654	(5,534)	(1,622)	(5,839)
Income attributable to sale of tax benefits	19,003	17,878	16,503	25,431	24,143
Gain from sale of property, plant and equipment	—	—	—	—	7,628
Other non-operating income (expense), net	7,779	(1,666)	(5,345)	(1,991)	756

Income from continuing operations, before income tax and equity in income (losses) of investees	137,181	170,730	141,088	113,599	85,836
Income tax (provision) benefit	(34,733)	(21,664)	(37,059)	16,057	(24,812)
Equity in earnings (losses) of investees, net	7,663	(1,957)	(7,735)	(5,508)	(3,213)
Income (loss) from continuing operations	110,111	147,109	96,294	124,148	57,811
Net income attributable to noncontrolling interest	(12,145)	(14,695)	(7,586)	(3,776)	(833)
Net income attributable to the Company's stockholders	$97,966	$132,414	$88,708	$120,372	$56,978

Table of Contents

	Year Ended December 31,				
	2018	**2017**	**2016**	**2015**	**2014**
	(Dollars in thousands, except per share data)				
Earnings per share attributable to the Company's stockholders:					
Basic:					
Net Income	$1.93	$2.64	$1.79	$2.48	$1.25
Diluted:					
Net Income	$1.92	$2.61	$1.77	$2.45	$1.24
Weighted average number of shares used in computation of earnings (loss) per share attributable to the Company's stockholders:					
Basic	50,643	50,110	49,469	48,562	45,508
Diluted	50,969	50,769	50,140	49,187	45,859
Dividend per share declared	$0.53	$0.41	$0.52	$0.26	$0.21
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$98,802	47,818	230,214	185,919	40,230
Working capital	111,120	38,301	283,579	186,635	67,521
Property, plant and equipment, net (including construction-in process)	2,221,268	2,028,233	1,863,087	1,808,170	1,734,359
Total assets	3,121,350	2,623,864	2,461,569	2,273,982	2,101,525
Long-term debt (including current portion)	1,108,913	862,102	938,844	901,403	981,379
Equity	1,445,096	1,295,700	1,168,272	1,087,307	789,324

Table of Contents

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.

General

Overview of Fiscal Year 2018 Revenues

For the year ended December 31, 2018, our total revenues increased by 3.8% (from $692.8 million to $719.3 million) over the previous year.

For the year ended December 31, 2018, Electricity segment revenues were $509.9 million, compared to $465.6 million for the year ended December 31, 2017, an increase of 9.5%. Product segment revenues for the year ended December 31, 2018 were $201.7 million, compared to $224.5 million for the year ended December 31, 2017, a decrease of 10.1%. Other segment revenues for the year ended December 31, 2018 were $7.6 million, compared to $2.7 million for the year ended December 31, 2017.

During the years ended December 31, 2018 and 2017, our consolidated power plants generated 5,857,963 MWh and 5,489,234 MWh, respectively, an increase of 6.7%

For the year ended December 31, 2018, our Electricity segment generated 70.9% of our total revenues (67.2% in 2017), while our Product segment generated 28.0% of our total revenues (32.4% in 2017), and our Other segment generated 1.1% of our total revenues (0.4% in 2017)

For the year ended December 31, 2018, approximately 94.8% 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 to 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.

To comply with obligations under their respective PPAs, certain of our project subsidiaries are structured as special purpose, bankruptcy remote entities and their assets and liabilities are ring-fenced. Such assets are not generally available to pay our debt, other than debt at the respective project subsidiary level. However, these project subsidiaries are allowed to pay dividends and make distributions of cash flows generated by their assets to us, subject in some cases to restrictions in debt instruments, as described below.

Electricity segment revenues are also subject to seasonal variations and can be affected by higher-than-average ambient temperatures, as described below under "Seasonality".

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.

Table of Contents

Revenues attributable to our Others segment are mainly derived from BSAAS systems, demand response and energy management services and may fluctuate between period to period. Pricing of such services and products are dependent on market supply and demand trends, market volatility, the need and price for ancillary services and other factors that may change over time.

Our management assesses the performance of our 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. We evaluate Other segment performance similar to the Electricity segment with respect to projects that we own and operate and similar to the Product segment when we provide services to third parties.

Trends and Uncertainties

Different 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.

PG&E which accounts for 1.9% of our total revenues, is facing extraordinary challenges relating to a series of catastrophic wildfires that occurred in Northern California in 2017 and 2018. If PG&E is found liable for the wildfires, its potential liabilities could exceed $30B. As a result, PG&E filed for reorganization under Chapter 11 bankruptcy. We are closely monitoring our PG&E account to ensure cash receipts are received timely each month and the payments due in January 2019 were received by Ormat and PG&E’s account is current. However, we cannot estimate at this stage the impact PG&E's current situation may have on us in the future.

In the Electricity segment, we expect intense domestic competition from the solar and wind power generation industries to continue and increase as well as increased competition from the solar combined with storage projects. 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 and reduction in energy storage costs are contributing 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.

Table of Contents

In the Product segment, we see new opportunities in Turkey, New Zealand, the U.S., Asia Pacific and Central and South America. 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 technology, 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 also leads to further reductions in the prices that we are able to charge for our binary equipment, as we recently experienced in Turkey, which in turn reduces our profitability. We are experiencing such competition in other locations where we operate which may have an adverse impact on the prices we can charge and our profitability.

The 38 MW Puna Complex has three PPAs, one of which (a 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 Puna power plant was shut-down on May 3, 2018 due to the volcano eruption in the Big Island, Hawaii (see further discussion under Recent Developments above).

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 are variable rates based on SRAC pricing that is impacted by natural gas prices.

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.

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, we earned, on average, $87.0 and $84.8 per MWh in 2018 and 2017, 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.

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 fourth globally with an installed geothermal capacity of over 1,300 MW. Since 2006, we have supplied and in the progress of supplying our state of the art binary equipment to approximately 40 projects in Turkey, which account for over 47% of the total installed geothermal capacity in Turkey as of December 2018. 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 increased in 2018 and expects to remain significant in 2019, as we signed a number of new contracts in Turkey. The continued deterioration in the Turkish economy, devaluation in the Turkish Lira and increase in local interest rates 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, collection from our customers 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.

Table of Contents

Ormat established a facility in Turkey in order to locally produce several power plant components that entitle our customer for 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.

While the recently enacted Tax Act reduces the corporate tax rate, it is also expected to increase the cost of capital for renewable energy projects. Such projects often rely on "tax equity" as a core financing tool. Tax equity is a form of financing that is repaid partly or wholly in tax benefits and sometimes partly in cash. There are two types of federal income tax benefits on renewable energy projects: a tax credit and depreciation, or the ability to deduct the cost of the project. The reduction in the corporate tax rate from 35 percent to 21 percent reduces the value of the depreciation. Therefore, less tax equity can be raised on projects. The gap in the capital structure must be filled with debt and/or more expensive sponsor equity. The Tax Act allowed the full cost of equipment acquired after September 27, 2017 to be deducted immediately. However, the tax equity market is not expected to be interested in this tax benefit and, in fact, because of the way tax equity works, the Company has had in some tax equity deals to take depreciation on a straight-line basis over 12 years rather than on a front-loaded basis over five years, which leads to some further erosion in the present value of the depreciation. Other effects of the Tax Act were discussed earlier under Note 18 – Income Taxes to our consolidated financial statements.

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 and the sale of BSAAS systems and demand response and energy management services.

Revenues attributable to our Electricity segment are derived from the sale of electricity from our power plants pursuant to long-term PPAs. While approximately 94.8% of our Electricity revenues for the year ended December 31, 2018 were derived from PPAs with fixed price components, we have variable price PPAs in California and Hawaii. 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. 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 and 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.

Revenues attributable to our Others segment are mainly derived from BSAAS systems, demand response and energy management services and may fluctuate period to period.

Table of Contents

Revenues attributable to our demand response and energy management services are derived by two methods. The first method is a fixed monthly or annual recurring fee for managing the customer's energy assets and monetizing them in either the energy markets or through reducing the customer's charges from their utility. The second method is through sharing the revenues or savings generated from monetizing their flexible electricity in the energy markets (revenue) or through reducing the customer's bill from the utility (savings). The second method is subject to energy price fluctuations and the available flexible electricity.

Revenues attributable to our Software as a Service are based on a fixed monthly or annual fee for energy management information and analytical services. Contract periods are typically 12 months or more. To date, we have experienced minimal customer churn.

BSAAS are battery storage deals that are financed, owned and operated by the Company. BSAAS revenues are a combination of sales of the electricity back to the utilities and energy markets based on the prevailing market price for the electricity or for the energy or ancillary services. The energy and ancillary services revenue includes frequency regulation, standby capacity, synchronized reserve, reactive power and other related services. Additionally, when providing a "behind the customer meter solution" we also generate revenue from sharing savings generated from reducing the customer's utility bill. We also act as a general contractor on turnkey BESS for customers. BESS systems are owned by the customer and we provide the EPC for the project, delivering to the customer a fully operational system. Along with the BESS we also provide the management and operation of the battery for the customer for the life of the system which is typically 10 to 20 years. The EPC portion of the turnkey BESS revenue is a one-time charge and usually will be based on mile-stones or upon delivery.

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,**		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Revenues:						
Electricity	$509,879	$465,593	$436,292	70.9 %	67.2 %	65.8 %
Product	201,743	224,483	226,299	28.0	32.4	34.2
Other	7,645	2,736	—	1.1	0.4	0.0
Total revenues	$719,267	$692,812	$662,591	100.0%	100.0%	100.0%

Geographic Breakdown of Results of Operations

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

	Revenues in Thousands			**% of Revenues for Period Indicated**		
	Year Ended December 31,			**Year Ended December 31,**		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Electricity Segment:						
United States	$305,962	$295,484	$288,842	60.0 %	63.5 %	66.2 %
International	203,917	170,109	147,450	40.0	36.5	33.8
Total	$509,879	$465,593	$436,292	100.0%	100.0%	100.0%
Product Segment:						
United States	$14,999	$2,912	$18,183	7.4 %	1.3 %	8.0 %
International	186,744	221,571	208,116	92.6	98.7	92.0
Total	$201,743	$224,483	$226,299	100.0%	100.0%	100.0%
Other Segment:						
United States	$7,645	$2,736	$—	100.0%	100.0%	0.0 %
Total	$7,645	$2,736	$—	100.0%	100.0%	0.0 %

Table of Contents

In 2018, 2017 and 2016, 54%, 57% and 54% of our revenues were derived from international operations, respectively, and our international operations were more profitable than our U.S. operations. A substantial portion of international revenues came from Kenya and Turkey and, to a lesser extent, from Guadeloupe, Guatemala and Honduras and other countries. Our operations in Kenya contributed disproportionately to gross profit and net income. 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 60%, 63% and 66% of our total Electricity segment for the years ended December 31, 2018, 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. Consequently, in 2018 the international operations of the segment accounted for 53% of our total gross profits, 77% of our net income and 53% of our EBITDA.

Product Segment. Our Product segment foreign revenues were 93%, 99% and 92% of our total Product segment revenues for the years ended December 31, 2018, 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 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.

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 and the prices under many of our contracts are fixed throughout the year with no time-of-use impact. 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 partially offset the negative impact on our revenues from lower generation in the summer attributable to the lower ambient temperature. As a result, we expect the revenues in the winter months to be higher than the revenues in the summer months.

Breakdown of Cost of Revenues

Electricity Segment

The principal cost of revenues attributable to our operating power plants are 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 4.2% and 4.1% of Electricity segment revenues for the years ended December 31, 2018 and December 31, 2017, respectively.

Product Segment

The principal cost of revenues attributable to our Product segment are 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.

Table of Contents

Other Segment

The principal cost of revenues attributable to our Other segment are direct costs attributable to providing services and equipment to our Viridity's customers, direct costs associated with software development and the direct cost of operating batteries that are owned by Viridity. Direct costs include labor costs of our network operations center, the labor costs for engineering and implementation of services to customers, consulting services provided to customers and developing software and the labor associated with operations and maintenance for customer and our Viridity owned energy assets. Cost of revenues attributable to our Other segment also include cost of equipment sold to customers in delivering our automated demand response and software services at a customer's location, the cost of batteries or other associated equipment that is sold to customers and for any third party related costs such as local construction, local engineering or other similar costs incurred in implementing and managing the customers' energy assets.

Cash and Cash Equivalents and Restricted Cash and Cash Equivalents

Our cash and cash equivalents and restricted cash and cash equivalents, increased to $177.5 million as of December 31, 2018, from $96.6 million as of December 31, 2017. This increase was attributable to: (i) $145.8 million derived from operating activities during the year ended December 31, 2018; (ii) $114.7 million of proceeds from a limited and non-recourse loan; (iii) net proceeds of $107.5 million from our revolving credit lines with commercial banks; (iv) $100.0 million of proceeds from a senior unsecured loan; (v) proceeds from sale of limited liability company interest in Tungsten, net of transaction costs of $32.2 million; (vi) restricted cash held by USG at acquisition date of $27.0 million; and (vii) cash received from insurance recoveries of $10.4 million. This increase was partially offset by: (i) our use of $258.5 million to fund capital expenditures; (ii) cash paid for acquisition of controlling interest in USG, net of cash acquired of $95.1 million; (iii) repayment of $62.8 million of long-term debt; (iv) a $26.8 million dividend paid; (v) $13.1 million paid to noncontrolling interest; and (vi) an investment in an unconsolidated company of $3.8 million. 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, 2018 was $468.0 million, as described below in "Liquidity and Capital Resources". As of December 31, 2018, we had utilized $365.4 million of our corporate borrowing capacity of which $144.9 million was utilized for cash withdrawals and the remainder for other letters of credit.

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.

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.

Table of Contents

- *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, 2018 and 2017, we determined that the geothermal resource at one and four 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 $0.1 million and $1.8 million of capitalized costs during the years ended December 31, 2018 and 2017, 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 $71.0 million and $63.9 million at December 31, 2018 and 2017, respectively. Included in these amounts at December 31, 2018 and 2017, respectively, are $ $17.0 million in each year that relate to up-front bonus payments.

- *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.

Table of Contents

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, 2018, 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.

Goodwill. Goodwill represents the excess of the fair value of consideration transferred in the business combination transactions over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any noncontrolling interest in the acquisitions. Goodwill is not amortized but rather subject to a periodic impairment testing on an annual basis (on December 31 of each year) or if an event occurs or circumstances change that would more likely than not reduce the fair value of reporting unit below its carrying amount. Additionally, we are permitted to first assess qualitative factors to determine whether a quantitative goodwill impairment test is necessary. Further testing is only required if the entity determines, based on the qualitative assessment, that it is more likely than not that a reporting unit's fair value is less than its carrying amount. Otherwise, no further impairment testing is required. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the quantitative goodwill impairment test. This would not preclude the entity from performing the qualitative assessment in any subsequent period. The first step compares the fair value of the reporting unit to its carrying value, including goodwill. An entity should recognize an impairment charge for the amount by which the carrying amount of the reporting unit exceeds its fair value as calculated under step one described above. However, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

- *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.

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.

Table of Contents

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.

Table of Contents

Results of Operations

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 power plants and enhancement of acquired power plants and (ii) fluctuation in revenues from our Product segment, and (iii) the impact of the lava eruption on our Puna plant in Hawaii.

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$509,879	$465,593	$436,292
Product	201,743	224,483	226,299
Other	7,645	2,736	—
	719,267	692,812	662,591
Cost of revenues:			
Electricity	298,255	266,840	261,573
Product	140,697	152,094	130,223
Other	9,880	5,426	—
	448,832	424,360	391,796
Gross profit (loss)			
Electricity	211,624	198,753	174,719
Product	61,046	72,389	96,076
Other	(2,235)	(2,690)	—
	270,435	268,452	270,795
Operating expenses:			
Research and development expenses	4,183	3,157	2,762
Selling and marketing expenses	19,802	15,600	16,424
General and administrative expenses	47,750	42,881	46,710
Impairment charge	13,464	—	—
Write-off of unsuccessful exploration activities	126	1,796	3,017
Operating income	185,110	205,018	201,882
Other income (expense):			
Interest income	974	988	971
Interest expense, net	(70,924)	(54,142)	(67,389)
Derivatives and foreign currency transaction gains (losses)	(4,761)	2,654	(5,534)
Income attributable to sale of tax benefits	19,003	17,878	16,503
Other non-operating income (expense), net	7,779	(1,666)	(5,345)
Income from continuing operations before income tax and equity in earnings (losses) of investees	137,181	170,730	141,088
Income tax (provision) benefit	(34,733)	(21,664)	(37,059)
Equity in earnings (losses) of investees, net	7,663	(1,957)	(7,735)
Income from continuing operations	110,111	147,109	96,294

Net income attributable to noncontrolling interest	(12,145)	(14,695)	(7,586)
Net income attributable to the Company's stockholders	$97,966	$132,414	$88,708
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$1.93	$2.64	$1.79
Diluted:			
Net income	$1.92	$2.61	$1.77
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,643	50,110	49,469
Diluted	50,969	50,769	50,140

Table of Contents

Results as a percentage of revenues

	Year Ended December 31,		
	2018	**2017**	**2016**
Revenues:			
Electricity	70.9 %	67.2 %	65.8 %
Product	28.0	32.4	34.2
Other	1.1	0.4	0.0
	100.0	100.0	100.0
Cost of revenues:			
Electricity	58.5	57.3	60.0
Product	69.7	67.8	57.5
Other	129.2	198.3	0.0
	62.4	61.3	59.1
Gross profit (loss)			
Electricity	41.5	42.7	40.0
Product	30.3	32.2	42.5
Other	(29.2)	(98.3)	0.0
	37.6	38.7	40.9
Operating expenses:			
Research and development expenses	0.6	0.5	0.4
Selling and marketing expenses	2.8	2.3	2.5
General and administrative expenses	6.6	6.2	7.0
Impairment charge	1.9	0.0	0.0
Write-off of unsuccessful exploration activities	0.0	0.3	0.5
Operating income	25.7	29.6	30.5
Other income (expense):			
Interest income	0.1	0.1	0.1
Interest expense, net	(9.9)	(7.8)	(10.2)
Derivatives and foreign currency transaction gains (losses)	(0.7)	0.4	(0.8)
Income attributable to sale of tax benefits	2.6	2.6	2.5
Other non-operating income (expense), net	1.1	(0.2)	(0.8)
Income from continuing operations before income tax and equity in earnings (losses) of investees	19.1	24.6	21.3
Income tax (provision) benefit	(4.8)	(3.1)	(5.6)
Equity in earnings (losses) of investees, net	1.1	(0.3)	(1.2)
Income from continuing operations	15.3	21.2	14.5
Net income attributable to noncontrolling interest	(1.7)	(2.1)	(1.1)
Net income attributable to the Company's stockholders	13.6 %	19.1 %	13.4 %

Comparison of the Year Ended December 31, 2018 and the Year Ended December 31, 2017

Total Revenues

Total revenues for the year ended December 31, 2018 were $719.3 million, compared to $692.8 million for the year ended December 31, 2017, representing a 3.8% increase from the prior period. This increase was attributable to our Electricity segment, in which revenues increased by $44.3 million or 9.5% compared to the corresponding period in 2017, and our Other segment in which revenues increased by $4.9 million or 179.4%, as a result of revenues generated by our Viridity business from the provision of energy storage, demand response and energy management services. This increase was partially offset by a decrease of $22.8 million, or 10.1% in our Product segment revenues compared to the corresponding period in 2017.

Table of Contents

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2018 were $509.9 million, compared to $465.6 million for the year ended December 31, 2017, representing a 9.5% increase from the prior period. This increase was primarily attributable to: (i) the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, with revenues of $34.4 million for the year ended December 31, 2018 compared to $10.0 million for the year ended December 31, 2017; (ii) the consolidation of USG which was acquired on April 24, 2018, with revenues of $21.4 million for year ended December 31, 2018. (iii) the commencement of commercial operation of our Tungsten Mountain power plant in Nevada, effective December 2017, with revenues of $15.7 million for the year ended December 31, 2018 compared to $2.2 million for the year ended December 31, 2017; (iv) the commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018; and (v) higher energy rates under the new Ormesa 1 PPA commencing in December 2017. The increase was partially offset due to (i) a decrease in revenues at our Puna power plant that was shut down immediately following the Kilauea volcanic eruption on May 3, 2018 and (ii) a decrease in generation at some of our other power plants that were taken offline to address maintenance issues and enhancements, high ambient temperature and curtailments.

Power generation in our power plants increased by 6.7% from 5,489,234 MWh in the year ended December 31, 2017 to 5,857,963 MWh in the year ended December 31, 2018, primarily because of an increase in generation due to the commencement of commercial operations of our Platanares power plant in Honduras, Tungsten Mountain power plant in Nevada, and Plant 1 expansion in Kenya and due to the acquisition of USG. The increase was partially offset by a decrease in generation at (i) our Puna power plant due to the Kilauea Volcanic Eruption and (ii) some of our other power plants mainly due to maintenance issues and high ambient temperature.

Product Segment

Revenues attributable to our Product segment for the year ended December 31, 2018 were $201.7 million, compared to $224.5 million for the year ended December 31, 2017, representing a 10.1% decrease from the prior period. The decrease in our Product segment revenues was attributable to the timing of revenue recognition. We recognized approximately $31.4 million and $23.1 million in revenues, from the New Zealand and China projects, respectively, in the year ended December 31, 2017, compared to $8.8 million and $0.5 million in the year ended December 31, 2018. The projects were completed in 2018. The decrease in our Product segment revenues was also attributable to other projects in Turkey, which were completed in 2017, and by a decrease in revenues as a result of completion of our contracts for geothermal projects in Chile and the Sarulla Project. The decrease was partially offset by the start of new projects in Turkey, which provided $154.3 million in revenue recognized during the year ended December 31, 2018.

Other Segment

Revenues attributable to our Other segment for the year ended December 31, 2018 were $7.6 million compared to $2.7 million for the year ended December 31, 2017. The other segment includes revenues from the provision of energy storage demand response and energy management services by our Viridity business following the acquisition of substantially all of the business and assets of Viridity Energy, Inc. on March 15, 2017.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2018 was $448.8 million, compared to $424.4 million for the year ended December 31, 2017, representing a 5.8% increase from the prior period. This increase was attributable to an increase of $31.4 million, or 11.8%, in cost of revenues from our Electricity segment and an increase of $4.5 million, or 82.1%, in cost of revenues from our Other segment generated by our Viridity business. This increase was partially offset by a 7.5% decrease in our Product segment cost of revenues compared to the corresponding period in 2017. As a percentage of total revenues, our total cost of revenues for the year ended December 31, 2018 increased to 62.4%, compared to 61.3% for the year ended December 31, 2017.

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2018 was $298.3 million, compared to $266.8 million for the year ended December 31, 2017, representing a 11.8% increase from the prior period. This increase was primarily attributable to additional cost of revenues from the commencement of commercial operation of our Platanares power plant in Honduras, effective September 2017, our Tungsten Mountain power plant in Nevada, effective December 2017 and commencement of commercial operation of our Plant 1 expansion project in the Olkaria III Complex in Kenya, effective June 2018, (ii) approximately $8.0 million higher costs compared to the same period 2017 related to pump failures that we had to replace in some of our power plants and (iii) the consolidation of USG which we acquired on April 24, 2018. As a percentage of total Electricity segment revenues, the total cost of revenues attributable to our Electricity segment for the year ended December 31, 2018 was 58.5%, compared to 57.3% for the year ended December 31, 2017. The cost of revenues attributable to our international power plants was 24.7% of our Electricity segment cost of revenues.

Product Segment

Total cost of revenues attributable to our Product segment for the year ended December 31, 2018 was $140.7 million, compared to $152.1 million for the year ended December 31, 2017, representing a 7.5% decrease from the prior period. This decrease was primarily attributable to decrease in Product segment revenues, as discussed above. As a percentage of total Product segment revenues, for the year ended December 31, 2018 was 69.7%, compared to 67.8% for the year ended December 31, 2017. This increase was primarily attributable to the higher competition, different product scope and different margins in the various sales contracts we entered into for the Product segment during these periods.

Other Segment

Cost of revenues attributable to our Other segment for the year ended December 31, 2018 were $9.9 million as compared to $5.4 million in the year ended December 31, 2017. The Other segment includes cost of revenues related to the provision of energy storage, demand response and energy management services by our Viridity business.

Research and Development Expenses

Research and development expenses for the year ended December 31, 2018 were $4.2 million, compared to $3.2 million for the year ended December 31, 2017.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2018 were $19.8 million, compared to $15.6 million for the year ended December 31, 2017. This increase was primarily due to the $5.0 million termination fee paid to NV Energy related to the termination of the Galena 2 PPA. The increase was partially offset as a result of lower sales commissions related to our Product segment due to lower revenues and lower commissions due to the nature of the contracts. Selling and marketing expenses for the year ended December 31, 2018 excluding the termination fee constituted 2.1% of total revenues for such year, compared to 2.3% for the year ended December 31, 2017.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2018 were $47.8 million, compared to $42.9 million for the year ended December 31, 2017.

This increase was primarily attributable to (i) general and administrative expenses resulting from first time inclusion of USG, (ii) general and administrative expenses from our Viridity business which we acquired on March 15, 2017; and (iii) an increase in costs associated with our identification of a material weakness related to taxes in the fourth quarter of 2017 and the additional work and controls to compensate for such material weakness as well as the restatement of second, third and fourth quarter financial statements and its full-year 2017 financial statements and related expenses. The increase was partially offset due to a $10.3 million adjustment in respect of an earn out related to the acquisition of our Viridity business. General and administrative expenses for the year ended December 31, 2017 included $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 22% of the Company.

Goodwill Impairment Charge

Goodwill impairment charge for the year ended December 31, 2018 was $13.5 million related to the acquisition of our Viridity business. There was no goodwill impairment charge for the year ended December 31, 2017.

Table of Contents

Write-off of Unsuccessful Exploration Activities

Write-off of unsuccessful exploration activities for the year ended December 31, 2018 was $0.1 million compared to $1.8 million for the year ended December 31, 2017. 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.

Operating Income

Operating income for the year ended December 31, 2018 was $185.1 million, compared to $205.0 million for the year ended December 31, 2017, representing a 9.7% decrease from the prior period. The decrease in operating income was primarily attributable to the $13.5 million goodwill impairment charge, the decrease in our Product segment gross margin, the $5.0 million termination fee of the Galena 2 PPA, and the increase in general and administrative expenses, as discussed above. The decrease was partially offset by an increase in our gross margin in our Electricity segment, also discussed above. Operating income attributable to our Electricity segment for the year ended December 31, 2018 was $155.5 million, compared to $157.6 million for the year ended December 31, 2017. Operating income attributable to our Product segment for the year ended December 31, 2018 was $38.1 million, compared to $50.5 million for the year ended December 31, 2017. Operating loss attributable to our Other segment for the year ended December 31, 2018 was $8.5 million compared to a loss of $3.1 million for the year ended December 31, 2017.

Interest Expense, Net

Interest expense, net, for the year ended December 31, 2018 was $70.9 million, compared to $54.1 million for the year ended December 31, 2017, representing a 31.0% increase from the prior period. This increase was primarily due to: (i) $100.0 million of proceeds from a senior unsecured loan received on March 22, 2018; (ii) net increase in our revolving credit lines with commercial banks; and (iii) a $3.5 million increase related to a decrease in interest capitalized to projects; (iv) additional debt as part of the acquisition of USG, and (v) $4.3 million increase in interest related to the sale of tax benefits; and (vi) $114.7 million of proceeds from a limited recourse loan received on October 29, 2018 from OPIC for financing the Honduras power plant, offset partially due to lower interest expense as a result of principal payments of long term debt.

Derivatives and Foreign Currency Transaction Gains (Losses)

Derivatives and foreign currency transaction losses for the year ended December 31, 2018 were $4.8 million, compared to gains of $2.7 million for the year ended December 31, 2017. Derivatives and foreign currency transaction losses for the year ended December 31, 2018 were attributable primarily to losses from foreign currency forward contracts, which were not accounted for as hedge transactions. Derivatives and foreign currency transaction gains for the year ended December 31, 2017 were primarily attributable to gains from foreign currency forward contracts, which were not accounted for as hedge transactions.

Income Attributable to Sale of Tax Benefits

Tax equity is a form of financing used for renewable energy projects. In such financings, the Company may realize income when the financing is put in place or over time as a consequence of how the financing is structured. Income attributable to such financings (as described below under “Opal Transaction”, “Tungsten Transaction”) for the year ended December 31, 2018 was $19.0 million, compared to $17.9 million for the year ended December 31, 2017. This income primarily represents the value of PTCs and taxable income or loss generated by Opal Geo and Tungsten allocated to the investor in the year ended December 31, 2018 compared to the value of PTCs and taxable income or loss generated by Opal Geo allocated to the investors in the year ended December 31, 2017.

Other Non-Operating Income (Expense), Net

Other non-operating income, net for the year ended December 31, 2018 was $7.8 million, compared to Other non-operating expense, net of $1.7 million for the year ended December 31, 2017. Other non-operating income, net for the year ended December 31, 2018 includes an income of $7.2 million insurance settlement of our Puna power plant rig which was damaged by the Kilauea volcanic eruption. 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.

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, 2018 was $137.2 million, compared to $170.7 million for the year ended December 31, 2017, representing a 19.7% decrease from the prior period. The income is primarily attributable to our foreign operations. This decrease was driven by the decrease in our domestic operations resulting mainly from the goodwill impairment charge relating to our Viridity business, the $5.0 million termination fee of the Galena 2 PPA, and the increase in general and administrative expenses, partially offset by an income of $7.2 million insurance settlement of our Puna power plant rig in the year ended December 31, 2018, as described above.

Income Taxes

Income tax provision for the year ended December 31, 2018, was $34.7 million, an increase of $13.0 million compared to an income tax provision of $21.7 million for the year ended December 31, 2017. The increase in income tax provision primarily resulted from the tax on global intangible low-tax income ("GILTI"), partially offset by a decrease in withholding tax on distribution of earnings, and the exclusion of other impacts of U.S. federal tax reform that resulted in a one-time tax impact for the year ended December 31, 2017. Our effective tax rate for the years ended December 31, 2018 and 2017, was 25.3% and 12.7%, respectively. Our effective tax rate at December 31, 2018 is principally based upon the composition of the income in different countries, tax on GILTI, accounting for intra-entity transfers of assets other than inventory, and changes related to valuation allowances. Our aggregate effective tax rate is higher than the 21% U.S federal statutory tax rate due to: (i) the impact of the newly enacted GILTI; (ii) higher tax rate in Kenya of 37.5% and Guadeloupe of 33.33% partially offset by a lower tax rate in Israel of 16 %; and (iii) withholding taxes on future distributions (see Note 18 – Income Taxes to the 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 years ended December 31, 2018 and 2017, we recorded a valuation allowance in the amount of approximately $22.4 million and $77.6 million, respectively, against our unutilized tax credits (FTCs and PTCs) and U.S. deferred tax assets related to state net operating loss (NOL) carryforwards. As of December 31, 2018, we had U.S. federal NOLs in the amount of approximately $230.5 million, state NOLs in the amount of approximately $269.1 million, and unutilized federal tax credits of approximately $149.0 million, some of which can be carried forward for 10-20 years. In addition, we had unutilized state tax credits of approximately 0.8 million, which can be carried forward for indefinite period. The related deferred tax assets totaled approximately $192.4 million after valuation allowance. Realization of these deferred tax assets and tax credits is dependent on generating sufficient taxable income in the U.S. prior to expiration 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 $22.4 million was recorded against the U.S. deferred tax assets as of December 31, 2018 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.

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act makes significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

The Company applied the guidance of SAB 118 for the effects of the Tax Act in 2017 and throughout 2018. The Deemed Repatriation Tax ("Transition Tax") is a tax on previously untaxed accumulated and current earnings and profits (E&P) of certain foreign subsidiaries. To determine the amount of the Transition Tax, we determined, in addition to other factors, the amount of post-1986 E&P of the relevant subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. As a result of our initial analysis of the impact of the Act, we recorded a provisional amount of $71.6 million (gross) with respect to the inclusion of the transition tax at December 31, 2017. In addition, at December 31, 2017, the Company recorded a provisional benefit of $22.6 million relating to the remeasurement of deferred taxes from 35% to 21%.

As of December 31, 2018, we have completed our accounting for the tax effects of the Tax Reform Act. . Subsequent adjustments to these amounts resulted in a reduction of $7.8 million the inclusion to the transition tax and a decreased tax benefit of $3.5 million to the remeasurement of deferred taxes.

Under the Tax Act, the deductibility of "net interest" for a business is limited to 30% of adjusted taxable income. The new proposed regulations issued by Treasury applies regardless of whether the interest payment is made to a US or foreign person, whether the interest recipient is related, or whether the interest recipient is exempt from US tax. Further, any interest that cannot be deducted in a year can be carried forward indefinitely. The Company has not early adopted these proposed regulations and intends to adopt during the 2019 tax year. For the year ended December 31, 2018, we have evaluated the impact and determined there is no limit on our interest deductibility for federal income tax purposes for the current period, but anticipates there could be significant limitations upon adoption.

The Company is also required to elect to either treat taxes due on future GILTI inclusions in U.S. taxable income as a current period expense when incurred or reflect such portion of the future GILTI inclusions in U.S. taxable income that relate to existing basis differences in the Company's current measurement of deferred taxes. The Company has elected to treat the taxes due on future U.S. inclusions in taxable income under GILTI as a period cost when incurred. The Company has elected and applied the tax law ordering approach when considering GILTI as part of the Company's valuation allowance.

We continue to monitor the impact of any additional guidance issued by Treasury. 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.

Equity in Earnings (losses) of investees, net

Equity in earnings (losses) of investees, net in the year ended December 31, 2018 was a profit of $7.7 million, compared to a loss of $2.0 million in the year ended December 31, 2017. Equity in earnings (losses) of investees, net derived from our 12.75% share in the earnings (losses) of the Sarulla project and from profits elimination. The increase was mainly attributable to utilization of carryforward losses and full year of commercial operations of SIL and NIL 1 and commercial operation of NIL 2 from May 2018.

Net Income

Net income for the year ended December 31, 2018 was $110.1 million, compared to $147.1 million for the year ended December 31, 2017, representing a decrease of $37.0 million from the prior period. This decrease in net income was primarily attributable to a decrease in operating income of $19.9 million, an increase of $16.8 million in interest expense, net and a decrease of $7.4 million in derivatives and foreign currency transaction gains and $13.1 million increase in income tax provision, partially offset due to an increase in Other non-operating income, net of $9.4 million, and an increase in equity in earnings of investees, net of $9.6 million, all as discussed above.

Net Income attributable to the Company's Stockholders

Net income attributable to the Company's stockholders for the year ended December 31, 2018 was $98.0 million, compared to $132.4 million for the year ended December 31, 2017, which represents a decrease of $34.4 million. This decrease was attributable to the decrease in net income of $37.0 million, offset partially by a decrease of $2.6 million in net income attributable to noncontrolling interest mainly due to the shutdown of the Puna power plant in Hawaii, all as discussed above.

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.

Electricity Segment

Revenues attributable to our Electricity segment for the year ended December 31, 2017, were $465.6 million, compared to $436.3 million for the year ended December 31, 2016, representing a 6.7% 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 and ; (iii) an increase in generation at our Puna power plant attributable to successful improvement of the resource performance. 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 recognized 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.

Other Segment

Revenues attributable to our Other segment for the year ended December 31, 2017 were $2.7 million. The other segment includes revenues from the provision of energy storage demand response and energy management services by our Viridity business following the acquisition of substantially all of the business and assets of Viridity Energy, Inc. on March 15, 2017.

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 an 8.3% increase from the prior period. This increase was attributable to an increase of $5.3 million, or 2.0%, in cost of revenues from our Electricity segment and an increase of $21.9 million, or 16.8% from our 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.

Table of Contents

Electricity Segment

Total cost of revenues attributable to our Electricity segment for the year ended December 31, 2017 was $266.8 million, compared to $261.6 million for the year ended December 31, 2016, representing a 2.0% 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 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 57.3%, 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.

Other Segment

Cost of revenues attributable to our Other segment for the year ended December 31, 2018 were $5.4 million in the year ended December 31, 2017. The Other segment includes cost of revenues related to the provision of energy storage, demand response and energy management services by our Viridity business.

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 commission 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.

Table of Contents

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 $157.6 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. Operating loss attributable to our Other segment for the year ended December 31, 2017 was $3.1 million for the year ended December 31, 2017.

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.

Derivatives and Foreign Currency Transaction 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 in our financial statements 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 Income (loss)

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.

Table of Contents

Income Taxes

Income tax provision for the year ended December 31, 2017, was $21.7 million, a decrease of $15.4 million compared to an income tax provision of $37.1 million for the year ended December 31, 2016. The decrease in income tax provision primarily resulted from the changes in valuation allowance and the impact of the U.S. tax reform legislation and partially offset by increase in income before taxes in jurisdictions outside of the U.S. and withholding tax on distribution of earnings. Our effective tax rate for the years ended December 31, 2017 and 2016, was 12.7% and 26.3%, respectively. Our effective tax rate at December 31, 2017 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. 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 on certain repatriated earnings of foreign subsidiaries (see Note 18– Income Taxes to the 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 years 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 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 $207.2 million, state NOLs in the amount of approximately $238.6 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 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.

Liquidity and Capital Resources

Our principal sources of liquidity have been derived from cash flows from operations, proceeds from third party debt such as borrowings under our credit facilities, private offerings and issuances of debt securities, project financing and 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, 2018, we had access to: (i) $98.8 million in cash and cash equivalents, of which $67.9 million was held by our foreign subsidiaries; and (ii) $78.8 million of unused corporate borrowing capacity under existing lines of credit with different commercial banks.

Our estimated capital needs for 2019 include approximately $250.0 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 $68.2 million for debt repayment.

As of December 31, 2018, $229.6 million in the aggregate was outstanding under credit agreements with several banks as detailed below under “Credit Agreements”.

We expect to finance these requirements with the sources of liquidity described above. Management believes that, based on the current stage of implementation of our strategic plan, the sources of liquidity and capital resources described above will address our anticipated liquidity, capital expenditures, and other investment requirements.

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 withholding taxes as part of repatriating 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.

Non-Recourse and Limited-Recourse Third-Party Debt

Loan	Issued Amount ($M)	Outstanding Amount as of December 31, 2018	Interest Rate	Maturity Date	Related Projects	Supplemental Information (see also Note 11 under the Financial Statements)
OrCal Geothermal Senior Secured Notes	165.0	18.7	6.21%	2020	Heber Complex	
OFC 2 Senior Secured Notes – Series A	151.7	101.8	4.67%	2032	McGinness Hills phase 1 and Tuscarora	
OFC 2 Senior Secured Notes – Series B	140.0	116.1	4.61%	2032	McGinness Hills phase 2	
Olkaria III Financing Agreement with OPIC – Tranche 1	85.0	56.6	6.34%	2030	Olkaria III Complex	
Olkaria III Financing Agreement with OPIC – Tranche 2	180.0	121.8	6.29%	2030	Olkaria III Complex	
Olkaria III Financing Agreement with OPIC – Tranche 3	45.0	32.2	6.12%	2030	Olkaria III Complex	
Amatitlan Financing	42.0	29.8	LIBOR+4.35%		Amatitlan	LIBO Rate cannot be lower than 1.25%. Margin of 4.35% as long as the Company's guaranty of the loan is outstanding (current situation) or 4.75% otherwise.
Don A. Campbell Senior Secured Notes	92.5	83.3	4.03%	2033	Don A. Campbell Complex	
Prudential Capital Group Idaho Loan	20.0	18.9	5.8%	2023	Neal Hot Springs and Raft River	Secured by equity interest
U.S. Department of Energy loan	96.8	51.3	2.6%	2035	Neal Hot Springs	Secured by the assets
Prudential Capital Group Nevada Loan	30.7	27.8	6.75%	2037	San Emidio	
	114.7	112.7	7.02%	2032	Platanares	

Platanares Loan with OPIC		
Total	**1163.4**	**771.0**

119

Table of Contents

Full-Recourse Third-Party Debt

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.

Credit Agreements	Issued Amount ($M)	Issued and Outstanding as of December 31, 2018	Termination Date	Supplemental Information (see also Note 11 under the Financial Statements)
Union Bank	60.0	51.5	June 2019	
HSBC	35.0	30.0	August 2019	
Other Banks 1	233.0	29.5	March 2019 – September 2019	
Other Banks 2	140.0	108.5	May 2019 – September 2019	
Total	**468.0**	**219.5**		

Credit Agreements

Credit Agreements	Issued Amount ($M)	Outstanding as of December 31, 2018	Interest Rate	Maturity Date	Supplemental Information (see also Note 11 under the Financial Statements)
Senior Unsecured Bonds Series 2	67.0	67.0	3.7%	September 2020	

Senior Unsecured Bonds Series 3	137.0	137.0	4.45%	September 2022
Senior unsecured Loan	100.0	100.0	4.8%	March 2029
DEG Loan	50.0	47.5	6.28%	June 2028
Total	**354**	**351.5**		

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, 2018: (i) total equity was $1,445.1 million and the actual equity to total assets ratio was 46.3% and (ii) the 12-month debt, net of cash, cash equivalents, to Adjusted EBITDA ratio was 3.21. During the year ended December 31, 2018, we distributed interim dividends in an aggregate amount of $26.8 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.

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

Table of Contents

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, 2018, are as follows:

	(Dollars in thousands)
Year ending December 31:	
2019	$ 68,180
2020	136,018
2021	64,039
2022	205,908
2023	84,101
Thereafter	570,751
Total	$ 1,128,997

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, 2018 amounted to $19.7 million, net of accumulated depreciation of $33.1 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 the 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 $1.3 million and $7.9 million as of December 31, 2018 and December 31, 2017, 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 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 PTCs and certain other tax benefits relating to the operation of five geothermal power plants located in Nevada.

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 Don A. Campbell 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.

Table of Contents

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.

Further details on the Opal Geo Transaction are provided under Note 13 of our Financial Statements.

Liquidity Impact of Uncertain Tax Positions

As discussed in Note 18 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 $11.8 million as of December 31, 2018. 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.

Dividends

The following are the dividends declared by us during the past two years:

Date Declared	**Dividend Amount per Share**	**Record Date**	**Payment Date**
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
May 7, 2018	$ 0.10	May 21, 2018	

			May 30, 2018
August 7, 2018	$ 0.10	August 21, 2018	August 29, 2018
November 6, 2018	$ 0.10	November 20, 2018	December 4, 2018
February 26, 2019	$ 0.11	March 14, 2019	March 28, 2019

Historical Cash Flows

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

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Net cash provided by operating activities	$145,822	$245,575	$159,285
Net cash used in investing activities	(342,434)	(345,526)	(173,772)
Net cash provided by (used in) financing activities	251,131	(67,882)	43,541
Net change in cash and cash equivalents and restricted cash and cash equivalents	53,859	(167,833)	29,054

For the Year Ended December 31, 2018

Net cash provided by operating activities for the year ended December 31, 2018 was $145.8 million, compared to $245.6 million for the year ended December 31, 2017. This decrease of $99.8 million resulted primarily from a decrease in accounts payable and accrued expenses of $56.7 million in the year ended December 31, 2018, compared to an increase of $51.6 million in the year ended December 31, 2017, mainly due to a withholding tax payment of approximately $44 million due to a distribution from OSL as a result of the change in our assertion on unrepatriated earnings of OSL to the U.S., in the second quarter of 2017, as discussed above, offset partially by approximately $14 million due to a distribution from OSL in 2018. The decrease was also due to timing of payments to our suppliers.

Net cash used in investing activities for the year ended December 31, 2018 was $342.4 million, compared to $345.5 million for the year ended December 31, 2017. The principal factors that affected our net cash used in investing activities during the year ended December 31, 2018 were: (i) capital expenditures of $258.5 million, primarily for our facilities under construction; (ii) cash paid for acquisition of controlling interest in USG, net of cash acquired of $95.1 million; (iii) and an investment in an unconsolidated company of $3.8 million.

Net cash provided by financing activities for the year ended December 31, 2018 was $251.1 million, compared to $67.9 million used for the year ended December 31, 2017. The principal factors that affected the net cash provided by financing activities during the year ended December 31, 2018 were: (i) $100.0 million of proceeds from a senior unsecured loan, (ii) $114.7 million of proceeds from a limited and non-recourse loan; (iii) net proceeds of $107.5 million from our revolving credit lines with commercial banks which were used for capital expenditures, and (iv) proceeds from the sale of a limited liability company interest in Tungsten, net of transaction costs of $32.2 million, partially offset by: (i) the repayment of long-term debt in the amount of $62.8 million; (ii) a $26.8 million cash dividend paid; and (iii) $13.1 million of cash paid to noncontrolling interests.

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 of $0.1 million in billing in excess of costs and estimated earnings on uncompleted contracts, net 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.

Net cash used in investing activities for the year ended December 31, 2017 was $345.5 million, compared to $173.8 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; and (iii) an investment in an unconsolidated company of $46.3 million.

Net cash used in financing activities for the year ended December 31, 2017 was $67.9 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; and (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.

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.

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.

Table of Contents

Adjusted EBITDA for the year ended December 31, 2018 was $368.0 million, compared to $343.8 million for the year ended December 31, 2017 and $323.8 million for the year ended December 31, 2016.

The following table reconciles Net income to EBITDA and adjusted EBITDA, for the years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31,		
	2018	2017	2016
	(in thousands)		
Net income	$110,111	$147,109	$96,294
Adjusted for:			
Interest expense, net (including amortization of deferred financing costs)	69,950	53,154	66,418
Income tax provision (benefit)	34,733	21,664	37,059
Adjustment to investment in an unconsolidated company: our proportionate share in interest expense, tax and depreciation and amortization in Sarulla	9,184	(265)	-
Depreciation and amortization	127,732	108,693	99,141
EBITDA	351,710	330,355	298,912
Mark-to-market on derivative instruments	2,032	(1,500)	319
Stock-based compensation	10,218	8,760	5,157
Gain on sale of subsidiary and property, plant and equipment	-	-	(686)
Insurance proceeds in excess of assets carrying value	(7,150)	-	-
Termination fee	4,973	-	-
Impairment of goodwill, net of reversal of a contingent liability	3,142	-	-
Loss from extinguishment of a liability	-	1,950	5,780
Merger and acquisition transaction costs	2,910	2,460	335
Settlement expenses	-	-	11,000
Write-off of unsuccessful exploration activities	126	1,796	3,017
Adjusted EBITDA	$367,961	$343,821	$323,834
Net cash used in investing activities	$(342,434)	$(345,526)	$(173,772)
Net cash used in financing activities	$251,131	$(67,882)	$43,541

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, 2018, the credit facility has an outstanding balance of $1,142.3 million. Our proportionate share in SOL credit facility is $145.6 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 $268.5 million in capital expenditures for construction of new projects and enhancements to our existing power plants, of which we have invested approximately $34.7 million as of December 31, 2018. We expect to invest $159.1 million in 2019 and the remaining $74.7 million thereafter.

Table of Contents

In addition, we estimate approximately $90.9 million in additional capital expenditures in 2019 to be allocated as follows: (i) $56.7 million for maintenance of capital expenditures to our operating power plants including drilling in our Puna power plant; (ii) $10.9 million for continued exploration activity under various geothermal prospects where we have already started exploration activity; (iii) $14.1 million for the construction and development of storage projects; and (iv) $9.2 million for enhancements to our production facilities.

In the aggregate, we estimate our total capital expenditures for 2019 to be approximately $250.0 million.

Exposure to Market Risks

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

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 between 30 MW and 40 MW PPAs in the aggregate 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, 2018, 96.8% of our consolidated long-term debt was fixed rate debt and therefore was not subject to interest rate volatility risk and 3.2 % of our long-term debt was floating rate debt, exposing us to interest rate risk in connection therewith. As of December 31, 2018, $36.0 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 except for our operations on Guadeloupe, where we own and operate the Boulliante power plant which sells its power under a Euro-denominated PPA with Électricité de France S.A. 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.

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, 2018 and 2017 by a hypothetical 10% and calculating the resulting change in the fair values.

Table of Contents

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, 2018 and 2017 are presented below:

Risk	Assuming a 10% Increase in Rates As of December 31, 2018	2017	Assuming a 10% Decrease in Rates As of December 31, 2018	2017	Change in the Fair Value of
	(In thousands)				
Foreign Currency	$(4,042)	$(5,181)	$4,940	$6,332	Foreign Currency Forward Contracts
Interest Rate	$(113)	$(193)	$114	$195	OrCal Senior Secured Notes
Interest Rate	$(5,955)	$(6,393)	$6,211	$6,662	OFC 2 Senior Secured Notes
Interest Rate	$(6,022)	$(6,710)	$6,294	$7,015	OPIC Loan
Interest Rate	$(714)	$- (1)	$745	$- (1)	Amatitlan loan
Interest Rate	$(3,054)	$(3,678)	$3,118	$3,766	Senior Unsecured Bonds
Interest Rate	$(1,216)	$(1,384)	$1,266	$1,442	DEG 2 Loan
Interest Rate	$(2,324)	$(2,476)	$2,438	$2,596	DAC 1 Senior Secured Notes
Interest Rate	$(2,897)	$-	$3,010	$-	Migdal Loan
Interest Rate	$(1,306)	$-	$1,398	$-	San Emidio Loan
Interest Rate	$(1,153)	$-	$1,197	$-	DOE Loan
Interest Rate	$(440)	$-	$453	$-	Idaho Holdings Loan
Interest Rate	$(3,719)	$-	$3,907	$-	Platanares OPIC Loan
Interest Rate	$(143)	$(171)	$148	$177	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 reducing 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.

Table of Contents

Contractual Obligations and Commercial Commitments

The following tables set forth our material contractual obligations as of December 31, 2018 (in thousands):

	Payments Due by Period						
	Remaining Total	2019	2020	2021	2022	2023	Thereafter
Long-term liabilities principal	$1,128,997	$68,180	$136,018	$64,039	$205,908	$84,101	$570,751
Interest on long-term liabilities (1)	362,952	56,934	53,090	46,817	43,185	40,564	122,362
Future minimum operating lease	35,958	7,771	4,197	3,475	2,474	1,603	16,438
Benefits upon retirement (2)	13,870	3,677	1,183	1,470	2,032	1,246	4,262
Asset retirement obligation	39,475	—	—	—	—	—	39,475
Purchase commitments (3)	129,300	129,300	—	—	—	—	—
	$1,710,552	$265,862	$194,488	$115,801	$253,599	$127,514	$753,288

(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 – Olkaria III Complex 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 Midgal Loan due in 2029 is fixed at a rate of 6.8%. Interest on the OPIC Loan – Platanares power plant - due in 2032 is fixed at a rate of 7.02%. Interest on the USG Prudential – NV due in 2037 is fixed at a rate of 6.75%. Interest on the USG Prudential - ID due in 2023 is fixed at a rate of 5.8%. Interest on the USG DOE due in 2035 is fixed at a rate of 2.6%. 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, 2018, total obligations related to such supplier agreements were approximately $129.3 million (approximately $36.1 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 $11.8 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 $69.9 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: Sierra Pacific Power Company and Nevada Power Company (subsidiaries of NV Energy), KPLC and SCPPA. If any of these electric utilities fail 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.

Sierra Pacific Power Company and Nevada Power Company accounted for 16.1%, 18.1%, and 19.2% of our total revenues for the three years ended December 31, 2018, 2017, and 2016, respectively.

KPLC accounted for 16.6%, 15.9%, and 16.5% of our total revenues for the three years ended December 31, 2018, 2017, and 2016, respectively.

SCPPA accounted for 15.2%, 10.1% and 10.2% of our total revenues for the three years ended December 31, 2018, 2017 and 2016, respectively.

Table of Contents

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.

Government Grants and Tax Benefits

The federal government encourages production of electricity from wind, solar and geothermal resources 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 tax 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. We will continue to analyze this new provision under the Act and determine if an election is appropriate as it relates to our 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.

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.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Index to Consolidated Financial Statements of Ormat Technologies, Inc. and Subsidiaries

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 sheet of Ormat Technologies, Inc. and its subsidiaries (the "Company") as of December 31, 2018 and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for the year then ended, 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, 2018, 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, 2018 and the results of its operations and its cash flows for the year then ended 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, 2018, 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 under Item 9A. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2018 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.

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.

Table of Contents

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/ Kesselman & Kesselman

Certified Public Accountants (Isr.)

A member firm of PricewaterhouseCoopers International Limited

Tel Aviv, Israel

March 1, 2019

We have served as the Company's auditor since 2018.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Ormat Technologies, Inc.:

Opinion on the Financial Statements

We have audited the consolidated balance sheet of Ormat Technologies, Inc. and its subsidiaries (the “Company”) as of December 31, 2017, and the related consolidated statements of operations and comprehensive income (loss), of equity and of cash flows for each of the two years in the period ended December 31, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s consolidated financial statements 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 of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

San Francisco, California

March 16, 2018, except for the effects of the restatement and revision discussed in Note 1 (not presented herein) to the consolidated financial statements appearing under Item 8 of the Company’s 2017 annual report on Form 10-K/A, as to which the date is June 19, 2018, and except for Note 1(a), as to which the date is March 1, 2019.

We served as the Company's auditor from 1988 to 2018.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	2017
	(Dollars in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$98,802	$47,818
Restricted cash and cash equivalents (primarily related to VIEs)	78,693	48,825
Receivables:		
Trade	137,581	110,410
Other	19,393	13,828
Inventories	45,024	19,551
Costs and estimated earnings in excess of billings on uncompleted contracts	42,130	40,945
Prepaid expenses and other	51,441	40,269
Total current assets	473,064	321,646
Investment in an unconsolidated company	71,983	34,084
Deposits and other	18,209	21,599
Deferred income taxes	113,760	57,337
Deferred charges	—	49,834
Property, plant and equipment, net ($1,859,228 and $1,631,900 related to VIEs, respectively)	1,959,578	1,734,691
Construction-in-process ($104,085 and $142,717 related to VIEs, respectively)	261,690	293,542
Deferred financing and lease costs, net	3,242	4,674
Intangible assets, net	199,874	85,420
Goodwill	19,950	21,037
Total assets	$3,121,350	$2,623,864
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$116,362	$153,796
Short term revolving credit lines with banks (full recourse)	159,000	51,500
Billings in excess of costs and estimated earnings on uncompleted contracts	18,402	20,241
Current portion of long-term debt:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes	33,493	33,226
Other loans	29,687	21,495
Full recourse	5,000	3,087
Total current liabilities	361,944	283,345
Long-term debt, net of current portion:		
Limited and non-recourse (primarily related to VIEs):		
Senior secured notes (less deferred financing costs of $7,434 and $8,113, respectively)	375,337	311,668
Other loans (less deferred financing costs of $9,354 and $5,258, respectively)	320,242	242,385
Full recourse:		
Senior unsecured bonds (less deferred financing costs of $758 and $580, respectively)	303,575	203,752
Other loans (less deferred financing costs of $921 and $1,011, respectively)	41,579	46,489
Liability associated with sale of tax benefits	69,893	44,634
Deferred lease income	48,433	51,520

Deferred income taxes	61,323	61,961
Liability for unrecognized tax benefits	11,769	8,890
Liabilities for severance pay	17,994	21,141
Asset retirement obligation	39,475	27,110
Other long-term liabilities	16,087	18,853
Total liabilities	1,667,651	1,321,748
Commitments and contingencies (Note 22)		
Redeemable noncontrolling interest	8,603	6,416
Equity:		
The Company's stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 50,699,781 and 50,609,051 shares issued and outstanding as of December 31, 2018 and December 31, 2017, respectively	51	51
Additional paid-in capital	901,363	888,778
Retained earnings	422,222	327,255
Accumulated other comprehensive loss	(3,799)	(4,706)
Total stockholders' equity attributable to Company's stockholders	1,319,837	1,211,378
Noncontrolling interest	125,259	84,322
Total equity	1,445,096	1,295,700
Total liabilities, redeemable noncontrolling interest and equity	$3,121,350	$2,623,864

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

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands, except per share data)		
Revenues:			
Electricity	$509,879	$465,593	$436,292
Product	201,743	224,483	226,299
Other	7,645	2,736	—
Total revenues	719,267	692,812	662,591
Cost of revenues:			
Electricity	298,255	266,840	261,573
Product	140,697	152,094	130,223
Other	9,880	5,426	—
Total cost of revenues	448,832	424,360	391,796
Gross profit	270,435	268,452	270,795
Operating expenses:			
Research and development expenses	4,183	3,157	2,762
Selling and marketing expenses	19,802	15,600	16,424
General and administrative expenses	47,750	42,881	46,710
Impairment charge	13,464	—	—
Write-off of unsuccessful exploration activities	126	1,796	3,017
Operating income	185,110	205,018	201,882
Other income (expense):			
Interest income	974	988	971
Interest expense, net	(70,924)	(54,142)	(67,389)
Derivatives and foreign currency transaction gains (losses)	(4,761)	2,654	(5,534)
Income attributable to sale of tax benefits	19,003	17,878	16,503
Other non-operating income (expense), net	7,779	(1,666)	(5,345)
Income from continuing operations before income taxes and equity in earnings (losses) of investees	137,181	170,730	141,088
Income tax (provision) benefit	(34,733)	(21,664)	(37,059)
Equity in earnings (losses) of investees, net	7,663	(1,957)	(7,735)
Income from continuing operations	110,111	147,109	96,294
Net income attributable to noncontrolling interest	(12,145)	(14,695)	(7,586)
Net income attributable to the Company's stockholders	$97,966	$132,414	$88,708

Comprehensive income:			
Net income	110,111	147,109	96,294
Other comprehensive income (loss), net of related taxes:			
Currency translation adjustments	(1,831)	3,440	(1,648)
Change in unrealized gains or losses in respect of the Company's share in derivatives instruments of unconsolidated investment	2,235	804	1,185
Loss in respect of derivative instruments designated for cash flow hedge	81	135	141
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge	(57)	(73)	(96)
Comprehensive income	110,539	151,415	95,876
Comprehensive income attributable to noncontrolling interest	(11,666)	(15,532)	(7,179)
Comprehensive income attributable to the Company's stockholders	$98,873	$135,883	$88,697
Earnings per share attributable to the Company's stockholders:			
Basic:			
Net income	$1.93	$2.64	$1.79
Diluted:			
Net income	$1.92	$2.61	$1.77
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:			
Basic	50,643	50,110	49,469
Diluted	50,969	50,769	50,140

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

Table of Contents

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, 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
Issuance of shares to noncontrolling interest, net of transaction costs	—	—	7,834	—	—	7,834	36,268	44,102
Increase in noncontrolling interest in Opal Geo	—	—	—	—	—	—	3,697	3,697
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
	—	—	—	—	1,185	1,185	—	1,185

Change in unrealized gains or 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 $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	—	—	—	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	—	—	—	—	135	135	—	135
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of	—	—	—	—	804	804	—	804

unconsolidated investment								
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $46)	—	—	—	—	(73)	(73)	—	(73)
Balance at December 31, 2017	50,609	$ 51	$ 888,778	$ 327,255	$ (4,706)	$ 1,211,378	$ 84,322	$ 1,295,700
Cumulative effect of changes in accounting principles	—	—	—	23,835	—	23,835	—	23,835
Adjusted balance as of the beginning of the year	50,609	51	888,778	351,090	(4,706)	1,235,213	84,322	1,319,535
Stock-based compensation	—	—	10,218	—	—	10,218	—	10,218
Exercise of stock-based awards by employees and directors	91	—	—	—	—	—	—	—
Cash paid to noncontrolling interest	—	—	—	—	—	—	(10,972)	(10,972)
Cash dividend declared, $0.53 per share	—	—	—	(26,834)	—	(26,834)	—	(26,834)
Increase in noncontrolling interest in Guadeloupe	—	—	—	—	—	—	5,339	5,339
Tax effect of partnership interest buyout	—	—	2,367	—	—	2,367	—	2,367
Increase in noncontrolling interest related to the Tungsten transaction	—	—	—	—	—	—	996	996
Purchase of USG	—	—	—	—	—	—	34,898	34,898
Net income	—	—	—	97,966	—	97,966	11,155	109,121
Other comprehensive income (loss), net of related taxes:								
Currency translation adjustment	—	—	—	—	(1,352)	(1,352)	(479)	(1,831)
Loss in respect of derivative	—	—	—	—	81	81	—	81

instruments designated for cash flow hedge (net of related tax of $24)								
Change in unrealized gains or losses in respect of the Company's share in derivative instruments of unconsolidated investment (net of related tax of $0)	—	—	—	—	2,235	2,235	—	2,235
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of $18)	—	—	—	—	(57)	(57)	—	(57)
Balance at December 31, 2018	50,700	$ 51	$ 901,363	$ 422,222	$ (3,799)	$ 1,319,837	$ 125,259	$ 1,445,096

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Cash flows from operating activities:			
Net income	$110,111	$147,109	$96,294
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	132,233	115,146	105,977
Amortization of premium from senior unsecured bonds	—	—	(513)
Accretion of asset retirement obligation	2,474	1,874	1,778
Stock-based compensation	10,218	8,760	5,157
Amortization of deferred lease income	(2,685)	(2,685)	(2,685)
Income attributable to sale of tax benefits, net of interest expense	(8,609)	(11,956)	(6,962)
Equity in losses (earnings) of investees	(7,663)	1,957	7,735
Mark-to-market of derivative instruments	2,032	(1,473)	319
Write-off of unsuccessful exploration activities	126	1,796	3,017
Impairment charge	13,464	—	—
Loss (gain) on severance pay fund asset	1,186	(1,746)	(304)
Deferred income tax provision and deferred charges	19,360	(41,147)	23,222
Liability for unrecognized tax benefits	2,879	3,270	(4,174)
Deferred lease revenues	(402)	(356)	(853)
Gain from insurance recoveries	(4,463)	—	—
Other	100	737	—
Changes in operating assets and liabilities, net of businesses acquired:			
Receivables	(29,928)	(24,040)	(33,280)
Costs and estimated earnings in excess of billings on uncompleted contracts	(1,185)	11,253	(27,078)
Inventories	(9,318)	(1,070)	6,297
Prepaid expenses and other	(11,172)	208	(12,540)
Deposits and other	18	(2,570)	(1,009)
Accounts payable and accrued expenses	(56,724)	51,641	(1,375)
Billings in excess of costs and estimated earnings on uncompleted contracts	(1,839)	(11,389)	(2,262)
Liabilities for severance pay	(3,147)	2,541	(786)
Other long-term liabilities	(11,244)	(2,285)	3,310
Net cash provided by operating activities	145,822	245,575	159,285
Cash flows from investing activities:			
Capital expenditures	(258,521)	(259,234)	(151,930)
Cash received from insurance recoveries related to destroyed equipment	10,427	—	—
Investment in unconsolidated companies	(3,800)	(46,318)	(3,569)

Buyout of Class B membership in ORTP	—	(2,400)	—
Buyout of Class B membership in OPC	2,367	(1,932)	—
Cash paid for acquisition of controlling interest in a subsidiary, net of cash acquired	(95,093)	(35,300)	(20,135)
Intangible assets acquired	—	(868)	—
Decrease (increase) in severance pay fund asset, net of payments made to retired employees	2,186	526	1,862
Net cash used in investing activities	(342,434)	(345,526)	(173,772)
Cash flows from financing activities:			
Proceeds from sale of membership interests to noncontrolling interest, net of transaction costs	3,174	—	44,102
Proceeds from long-term loans, net of transaction costs	214,700	—	142,500
Proceeds from exercise of options by employees	—	16,111	7,249
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 Tungsten, net of transaction costs	32,175	—	59,897
Purchase of OFC Senior Secured Notes	—	(14,270)	(6,815)
Proceeds from revolving credit lines with banks	4,097,000	1,097,500	309,400
Repayment of revolving credit lines with banks	(3,989,500)	(1,046,000)	(309,400)
Cash received from noncontrolling interest	4,134	2,017	1,972
Cash paid for achievement of production threshold in GB	—	(8,032)	—
Repayments of long-term debt	(62,774)	(66,223)	(62,052)
Cash paid to noncontrolling interest	(13,106)	(21,313)	(64,065)
Payments of capital leases	(2,551)	(1,871)	(1,178)
Deferred debt issuance costs	(5,287)	(5,290)	(6,402)
Cash dividends paid	(26,834)	(20,511)	(25,682)
Net cash provided by (used in) financing activities	251,131	(67,882)	43,541
Effect of exchange rate changes	(660)	—	—
Net change in cash and cash equivalents and restricted cash and cash equivalents	53,859	(167,833)	29,054
Restricted cash and cash equivalents acquired in a business combination	26,993	—	—
Cash and cash equivalents and restricted cash and cash equivalents at beginning of period	96,643	264,476	235,422
Cash and cash equivalents and restricted cash and cash equivalents at end of period	$177,495	$96,643	$264,476
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$53,864	$40,484	$55,366
Income taxes, net	$18,028	$21,878	$18,490
Supplemental non-cash investing and financing activities:			
Increase (decrease) in accounts payable related to purchases of property, plant and equipment	$(6,878)	$4,484	$(2,219)
Accrued liabilities related to financing activities	$8,584	$—	$6,291
Increase (decrease) in asset retirement cost and asset retirement obligation	$881	$1,888	$714

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

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Business

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 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 PURPA. The 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, 2018.

Cash dividends

During the years ended December 31, 2018, 2017, and 2016, the Company's Board of Directors (the "Board") declared, approved, and authorized the payment of cash dividends in the aggregate amount of $26.8 million ($0.53 per share), $20.5 million ($0.41 per share), and $25.7 million ($0.52 per share), respectively. Such dividends were paid in the years declared.

Rounding

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

Basis of presentation

The consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") and include the accounts of the Company and of all majority-owned subsidiaries in which the Company exercises control over operating and financial policies, and variable interest entities in which the Company has an interest and is the primary beneficiary. Intercompany accounts and transactions have been eliminated in consolidation.

Investments in less-than-majority-owned entities or other entities in which the Company exercises significant influence over operating and financial policies are accounted for using the equity method of accounting or consolidated if they are a variable interest entity in which the Company has an interest and is the primary beneficiary. Under the equity method, original investments are recorded at cost and adjusted by the Company's share of undistributed earnings or losses of such companies. The Company's earnings or losses in investments accounted for under the equity method have been reflected as "equity in earnings (losses) of investees, net" on the Company's consolidated statements of operations and comprehensive income (loss).

Cash and cash equivalents

The Company considers all highly liquid instruments, with an original maturity of three months or less, to be cash equivalents.

Restricted cash, cash equivalents, and marketable securities

Under the terms of certain long-term debt agreements, the Company is required to maintain certain debt service reserves, cash collateral and operating fund accounts that have been classified as restricted cash and cash equivalents. Funds that will be used to satisfy obligations due during the next twelve months are classified as current restricted cash and cash equivalents, with the remainder classified as non-current restricted cash and cash equivalents. Such amounts were invested primarily in money market accounts and commercial paper with a minimum investment grade of "AA".

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Reconciliation of Cash and cash equivalents and Restricted cash and cash equivalents

The following table provides a reconciliation of Cash and cash equivalents and Restricted cash and cash equivalents reported on the balance sheet that sum to the total of the same amounts shown on the statement of cash flows:

	December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Cash and cash equivalents	$98,802	$47,818	$230,214
Restricted cash and cash equivalents	78,693	48,825	34,262
Total Cash and cash equivalents and restricted cash and cash equivalents	$177,495	$96,643	$264,476

Concentration of credit risk

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

The Company places its temporary cash investments with high credit quality financial institutions located in the U.S. and in foreign countries. At December 31, 2018 and 2017, the Company had deposits totaling $31.3 million and $21.2 million, respectively, in ten U.S. financial institutions (seven such banks in the prior year) that were federally insured up to $250,000 per account. At December 31, 2018 and 2017, the Company's deposits in foreign countries of approximately $93.9 million and $32.8 million, respectively, were not insured.

At December 31, 2018 and 2017, accounts receivable related to operations in foreign countries amounted to approximately $102.0 million and $78.1 million, respectively. At December 31, 2018, and 2017, accounts receivable from the Company's major customers (see Note 19) amounted to approximately 56% and 57%, respectively, of the Company's accounts receivable.

The Company has historically been able to collect on substantially all of its receivable balances and believes it will continue to be able to collect all amounts due. Accordingly, no provision for doubtful accounts has been made.

Additionally, one of our off-takers, PG&E, which accounts for approximately 1.9% of our total revenues, filed for reorganization under Chapter 11 bankruptcy. We are closely monitoring our PG&E account to ensure cash receipts are received timely each month and the payments due in January 2019 were received and PG&E's account is current. However, we cannot estimate at this stage what the future impact of PG&E current situation may have on us.

Inventories

Inventories consist primarily of raw material parts and sub-assemblies for power units and are stated at the lower of cost or net realizable value, using the weighted-average cost method. Inventories are reduced by a provision for slow-moving and obsolete inventories. This provision was not material at December 31, 2018 and 2017.

Deposits and other

Deposits and other consist primarily of performance bonds for construction projects, long-term insurance contract and receivables, and derivative instruments.

Deferred charges

Deferred charges represent prepaid income taxes on intercompany sales. Such amounts were amortized using the straight-line method and included in income tax provision over the life of the related property, plant and equipment. The Company adopted Accounting Standards Update 2016-16, Income Taxes on Intercompany Transfers in its consolidated financial statements for the first quarter of 2018 using the modified retrospective approach. As a result, there was an adjustment to deferred charges with a corresponding adjustment to deferred income taxes of $49.8 million with an immaterial amount recorded to retained earnings. For additional information on the new accounting standard related to tax effects associated with intra-company transfers of assets please see "New accounting pronouncements effective in the year ended December 31, 2018" below.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Property, plant and equipment, net

Property, plant and equipment are stated at cost. All costs associated with the acquisition, development and construction of power plants operated by the Company are capitalized. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. Power plants operated by the Company, which include geothermal wells and exploration and resource development costs, are depreciated using the straight-line method over their estimated useful lives, which range from 15 to 30 years. The other assets are depreciated using the straight-line method over the following estimated useful lives of the assets:

Buildings (in years)		25	
Leasehold improvements (in years)	15	-	20
Machinery and equipment — manufacturing and drilling (in years)		10	
Machinery and equipment — computers (in years)	3	-	5
Office equipment — furniture and fixtures (in years)	5	-	15
Office equipment — other (in years)	5	-	10
Automobiles (in years)	5	-	7

The cost and accumulated depreciation of items sold or retired are removed from the accounts. Any resulting gain or loss is recognized currently and recorded in the accompanying statements of operations.

The Company capitalizes interest costs as part of constructing power plant facilities. Such capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset’s estimated useful life. Capitalized interest costs amounted to $3.7 million, $7.2 million, and $3.3 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Exploration and development costs

The Company capitalizes costs incurred in connection with the exploration and development of geothermal resources once it acquires land rights to the potential geothermal resource. Prior to acquiring land rights, the Company makes an initial assessment that an economically feasible geothermal reservoir is probable on that land. The Company determines the economic feasibility of potential geothermal resources internally, with all available data and external assessments vetted through the exploration department and occasionally using outside service providers. Costs associated with the initial assessment are expensed and included in cost of electricity revenues in the consolidated statements of operations and comprehensive income (loss). Such costs were immaterial during the years ended December 31, 2018, 2017 and 2016. It normally takes two to three years from the time active exploration of a particular geothermal resource begins to the time a production well is in operation, assuming the resource is commercially viable. However, in certain sites the process may take longer due to permitting delays, transmission constraints or any other commercial milestones that are required to be reached in order to pursue the development process.

In most cases, the Company obtains the right to conduct the geothermal development and operations on land owned by the BLM, various states or with private parties. In consideration for certain of these leases, the Company may pay an up-front bonus payment which is a component of the competitive lease process. The up-front bonus payments and other related costs, such as legal fees, are capitalized and included in construction-in-process. The annual land lease payments made during the exploration, development and construction phase are expensed as incurred and included in "electricity cost of revenues" in the consolidated statements of operations and comprehensive income (loss). Upon commencement of power generation on the leased land, the Company begins to pay to the lessor's long-term royalty payments based on the utilization of the geothermal resources as defined in the respective agreements. Such payments are expensed when the related revenues are earned and included in "electricity cost of revenues" in the consolidated statements of operations and comprehensive income (loss).

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Following the acquisition of land rights to the potential geothermal resource, the Company conducts further studies and surveys, including water and soil analyses among others, and augments its database with the results of these studies. The Company then initiates a suite of geophysical surveys to assess the resource and determine drilling locations. If the results of these activities support the initial assessment of the feasibility of the geothermal resource, the Company then proceeds to exploratory drilling and other related activities which may include drilling of temperature gradient holes, drilling of slim holes, building access roads to drilling locations, drilling full size production and/or injection wells and flow tests. If the slim hole supports a conclusion that the geothermal resource will support a commercially viable power plant, it may be converted to a full-size commercial well, used either for extraction or re-injection of geothermal fluids, or be used as an observation well to monitor and define the geothermal resource. Costs associated with these activities and other directly attributable costs, including interest once physical exploration activities begin and permitting costs are capitalized and included in “construction-in-process”. If the Company concludes that a geothermal resource will not support commercial operations, capitalized costs are expensed in the period such determination is made.

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, write-off of unsuccessful activities for the year ended December 31, 2018, 2017 and 2016 was $0.1 million, $1.8 million, and $3.0 million. In 2017, the write-offs included exploration costs related to the Company’s exploration activities in Oregon, and in 2016, the write-offs included the exploration costs related to the Company’s exploration activities in Nevada and Chile, after which the Company determined that the applicable sites would no longer support commercial operation.

Grants received from the U.S. DOE are offset against the related exploration and development costs. There were no such grants for the years ended December 31, 2018 and 2017. The amount of such grants for the year ended December 31, 2016 was $0.3 million.

All exploration and development costs that are being capitalized, including the up-front bonus payments made to secure land leases, will be depreciated over their estimated useful lives when the related geothermal power plant is substantially complete and ready for use. A geothermal power plant is substantially complete and ready for use when electricity generation commences.

Asset retirement obligation

The Company records the fair value of a legal liability for an asset retirement obligation in the period in which it is incurred. The Company's legal liabilities include plugging wells and post-closure costs of power producing sites. When a new liability for asset retirement obligations is recorded, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. The Company periodically reassess the assumptions used to estimate the expected cash flows required to settle the asset retirement obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the asset retirement obligation, as well as changes in the legal requirements of an obligation and revises the previously recorded asset retirement obligation accordingly. At retirement, the obligation is settled for its recorded amount at a gain or loss.

Deferred financing and lease transaction costs

Deferred financing costs are amortized over the term of the related obligation using the effective interest method. Amortization of deferred financing costs is presented as interest expense in the consolidated statements of operations and comprehensive income (loss). Accumulated amortization related to deferred financing costs amounted to $21.8 million and $31.0 million at December 31, 2018 and 2017, respectively. Amortization expense for the years ended December 31, 2018, 2017, and 2016 amounted to $4.6 million, $5.7 million, and $6.9 million, respectively. During the years ended December 31, 2018, 2017 and 2016, amounts of $0.0 million, $0.6 million and $0.1 million, respectively, were written-off as a result of the extinguishment of liability.

Deferred transaction costs relating to the Puna operating lease (see Note 12) in the amount of $4.2 million are amortized using the straight-line method over the 23-year term of the lease. Amortization of deferred transaction costs is presented in cost of revenues in the consolidated statements of operations and comprehensive income (loss). Accumulated amortization related to deferred lease costs amounted to $2.5 million and $2.3 million at December 31, 2018 and 2017, respectively. Amortization expense for each of the years ended December 31, 2018, 2017, and 2016 amounted to $0.2 million.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Goodwill

Goodwill represents the excess of the fair value of consideration transferred in the business combination transactions of Guadeloupe, Viridity and USG over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and the fair value of any noncontrolling interest in the acquisitions. Goodwill is not amortized but rather subject to a periodic impairment testing on an annual basis (on December 31 of each year) or if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. Additionally, an entity is permitted to first assess qualitative factors to determine whether a quantitative goodwill impairment test is necessary. Further testing is only required if the entity determines, based on the qualitative assessment, that it is more likely than not that a reporting unit's fair value is less than its carrying amount. Otherwise, no further impairment testing is required. An entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the quantitative goodwill impairment test. This would not preclude the entity from performing the qualitative assessment in any subsequent period. The first step compares the fair value of the reporting unit to its carrying value, including goodwill. In January 2017, the FASB issued ASU 2017-04, Intangibles – Goodwill and Other (Topic 350), which was early adopted by the Company in 2018, under which step two of the goodwill impairment test is eliminated. Step two measured a goodwill impairment test by comparing the implied fair value of reporting unit's goodwill with the carrying amount of that goodwill. For additional information on this new accounting standard please see "New accounting pronouncements effective in the year ended December 31, 2018" below. Under ASU 2017-04, Intangibles – Goodwill and Other, an entity should recognize an impairment charge for the amount by which the carrying amount of the reporting unit exceeds its fair value as calculated under step one described above. However, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. For further information relating to goodwill see Note 9 - Intangible assets and goodwill to the consolidated financial statements.

Intangible assets

Intangible assets consist of allocated acquisition costs of PPAs, which are amortized using the straight-line method over the 13 to 25-year terms of the agreements (see Note 9) as well as acquisition cost allocation related to Viridity's storage activities that are amortized over a weighted average amortization period of 19 years. Intangible assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. In case there is no such events or change in circumstances, there is no need to perform the impairment testing. The recoverability is tested by comparing the net carrying value of the intangible assets to the undiscounted net cash flows to be generated from the use and eventual disposition of that asset. If the carrying amount of a long-lived asset (or asset group) is not recoverable, the fair value of the asset (asset group) is measured and if the carrying amount exceeds the fair value, an impairment loss is recognized.

Impairment of long-lived assets and long-lived assets to be disposed of

The Company evaluates 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 the Company’s use of assets or its 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 its business or when it concludes that it is more likely than not that an asset will be disposed of or sold.

The Company tests its 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 combined operation management generally with one central control room that controls all of the power plants in a complex 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. The Company tests for impairment its operating plants which are not operated as a complex as well as its 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, the Company 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 the Company uses in estimating its undiscounted future cash flows include: (i) projected generating capacity of the complex or power plant and rates to be received under the respective PPA(s) and expected market rates thereafter and (ii) projected operating expenses of the relevant complex or 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.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

If the assets are considered to be impaired, the impairment to be recognized is measured by 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. Management believes that no impairment exists for long-lived assets; however, estimates as to the recoverability of such assets may change based on revised circumstances. If actual cash flows differ significantly from the Company’s current estimates, a material impairment charge may be required in the future.

Derivative instruments

Derivative instruments (including certain derivative instruments embedded in other contracts) are measured at their fair value and recorded as either assets or liabilities unless exempted from derivative treatment as a normal purchase and sale. All changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met, which requires a company to formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

The Company maintains a risk management strategy that may incorporates the use of swap contracts and put options on oil and natural gas prices, forward exchange contracts, interest rate swaps, and interest rate caps to minimize significant fluctuation in cash flows and/or earnings that are caused by oil and natural gas prices, exchange rate or interest rate volatility. Gains or losses on contracts that initially qualify for cash flow hedge accounting, net of related taxes, are included as a component of other comprehensive income or loss and accumulated other comprehensive income or loss are subsequently reclassified into earnings when the hedged forecasted transaction affects earnings. Gains or losses on contracts that are not designated as a cash flow hedge are included currently in earnings.

Foreign currency translation

The U.S. dollar is the functional currency for all of the Company’s consolidated operations and those of its equity affiliates except for the Guadeloupe power plant. For those entities, all gains and losses from currency translations are included within the line item “Derivatives and foreign currency transaction gains (losses)” within the consolidated statements of operations and comprehensive income (loss). The Euro is the functional currency of the Guadeloupe power plant and thus gains and losses from currency translation adjustments related to Guadeloupe are included as currency translation adjustments in accumulated other comprehensive income in the consolidated statements of equity and in comprehensive income. The accumulated currency translation adjustments amounted to $0.0 million and $1.4 million as of December 31, 2018 and 2017, respectively.

Comprehensive income (loss) reporting

Comprehensive income (loss) includes net income or loss plus other comprehensive income (loss), which for the Company consists of changes in unrealized gains or losses in respect of the Company’s share in derivatives instruments of unconsolidated investment, foreign currency translation adjustments and amortization of unrealized gains in respect of derivative instruments designated as a cash flow hedge. The changes in foreign currency translation adjustments, amortization of unrealized gains and loss in respect of derivative instruments designated as a cash flow hedge during the years ended December 31, 2018, 2017 and 2016 were immaterial. The change in the Company’s share in derivative instruments of unconsolidated investment is disclosed under Note 5 – Investment in unconsolidated companies to the consolidated financial statements.

Revenues and cost of revenues

Revenues are primarily related to: (i) sale of electricity from geothermal and recovered energy-based power plants owned and operated by the Company; (ii) geothermal and recovered energy-based power plant equipment engineering, sale, construction and installation, and operating services and (iii) energy storage, demand-response and energy management services.

Electricity segment revenues: Revenues related to the sale of electricity from geothermal and recovered energy-based power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For PPAs agreed to, modified, or acquired in business combinations on or after July 1, 2003, the Company determines whether such PPAs contain a lease element requiring lease accounting. Revenue from such PPAs are accounted for in electricity revenues. The lease element of the PPAs is also assessed in accordance with the revenue arrangements with multiple deliverables guidance, which requires that revenues be allocated to the separate earnings processes based on their relative fair value. PPAs with minimum lease rentals which vary over time are generally recognized on the straight-line basis over the term of the PPAs. PPAs with contingent rentals are recognized when earned. In the electricity segment, revenues for all but four power plants are accounted for under ASC 840 (Leases) as operating leases, and therefore equipment related to geothermal and recovered energy generation power plants as described in Note 8 is considered held for leasing. For power plants in the scope of ASC 606, the Company identified electricity as a separate performance obligation. Performance obligations identified were evaluated and determined to be satisfied over time and qualified for the invoicing practical expedient since the invoiced amounts reasonably represented the value to customers of performance obligations fulfilled to date. The transaction price is determined based on the price per actual mega-watt output or available capacity as agreed to in the respective PPA. Customers are generally billed on a monthly basis and payment is typically due within 30 to 60 days after the issuance of the invoice.

142

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Product segment revenues: Revenues from engineering, operating services, and parts and product sales are recorded upon providing the service or delivery of the products and parts and when collectability is reasonably assured. Revenues from the supply and/or construction of geothermal and recovered energy-based power plant equipment and other equipment to third parties are recognized over time since control is transferred continuously to our customers. The majority of our contracts include a single performance obligation which is essentially the promise to transfer the individual goods or services that are not separately identifiable from other promises in the contracts and therefore deemed as not distinct. Performance obligations are satisfied over-time if the customer receives the benefits as we perform work, if the customer controls the asset as it is being constructed, or if the product being produced for the customer has no alternative use and we have a contractual right to payment. In our Product segment, revenues are spread over a period of one to two years and are recognized over time based on the cost incurred to date in ratio to total estimated costs which represents the input method that best depicts the transfer of control over the performance obligation to the customer. Costs include direct material, labor, and indirect costs. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined.

In contracts for which we determine that control is not transferred continuously to the customer, we recognized revenues at the point in time when the customer obtains control of the asset. Revenues for such contracts are recorded upon delivery and acceptance by the customer. This generally is the case for the sale of spare parts, generators or similar products.

Accounting for product contracts that are satisfied over time includes use of several estimates such as variable consideration related to bonuses and penalties and total estimated cost for completing the contract. The estimated amount of variable consideration will be included in the transaction price only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. These estimates are based on historical experience, anticipated performance and our best judgment at the time.

The nature of our product contracts give rise to several modifications or change requests by our customers. Substantially all of the modifications are treated as cumulative catch-ups to revenues since the additional goods are not distinct from those already provided. We include the additional revenues related to the modifications in our transaction price when both parties to the contract approved the modification. As a significant change in one or more of these estimates could affect the profitability of our contracts, we review and update our contract-related estimates regularly. We recognize adjustments in Product revenues on contracts under the cumulative catch-up method. If at any time the estimate of contract profitability indicates an anticipated loss on the contract, we recognize the total loss in the period in which it is identified.

Other segment revenues: Energy storage, demand-response and energy management related services revenues are recorded based on energy management of load curtailment capacity delivered or service provided at rates specified under the relevant contract terms. The Company determined that such revenues are in the scope of ASC 606 and identified energy management as a separate performance obligation. Performance obligations are satisfied once the Company provides verification to the electric power grid operator or utility of its ability to meet the committed capacity or power curtailment requirements and thus entitled to cash proceeds. Such verification may be provided by the Company bi-weekly, monthly or under any other frequency as set by the related program and are typically followed by a payment shortly after. Performance obligations identified were evaluated and determined to be satisfied over time and qualified for the invoicing practical expedient since the amounts included in the verification document reasonably represent the value of performance obligations fulfilled to date. The transaction price is determined based on mechanisms specified in the contract with the customer.

For additional information please see "Revenues from Contracts with Customers" under "New accounting pronouncement" section below.

Our accounting policy for revenues included under the comparative periods were accounted under the previous accounting standard as follows:

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenues related to the sale of electricity from geothermal and recovered energy-based power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For PPAs agreed to, modified, or acquired in business combinations on or after *July 1, 2003,* the Company determines whether such PPAs contain a lease element requiring lease accounting. Revenue from such PPAs are accounted for in electricity revenues. The lease element of the PPAs is also assessed in accordance with the revenue arrangements with multiple deliverables guidance, which requires that revenues be allocated to the separate earnings processes based on their relative fair value. PPAs with minimum lease rentals which vary over time are generally recognized on the straight-line basis over the term of the PPAs. PPAs with contingent rentals are recognized when earned. In the electricity segment, revenues for all but two power plants are accounted for under ASC 840 (Leases) as operating leases, and therefore equipment related to geothermal and recovered energy generation power plants as described in Note 8 is considered held for leasing.

Revenues from engineering, operating services, and parts and product sales are recorded upon providing the service or delivery of the products and parts and when collectability is reasonably assured. Revenues from the supply and/or construction of geothermal and recovered energy-based power plant equipment and other equipment to *third* parties are recognized using the percentage-of-completion method. Revenue is recognized based on the percentage relationship that incurred costs bear to total estimated costs. Costs include direct material, labor, and indirect costs. Selling, marketing, general, and administrative costs are charged to expense as incurred. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. Changes in job performance, job conditions, and estimated profitability, including those arising from contract penalty provisions and final contract settlements, *may* result in revisions to costs and revenues and are recognized in the period in which the revisions are determined.

In specific instances where there is a lack of dependable estimates or inherent risks cause forecast to be doubtful, then the completed-contract method is followed. Revenue is recognized when the contract is substantially complete and when collectability is reasonably assured. Costs that are closely associated with the project are deferred as contract costs and recognized similarly to the associated revenues.

Termination fee

Fees to terminate PPAs are recognized in the period incurred as selling and marketing expenses. During 2018, the Company signed a termination agreement with NV Energy, Inc. for the Galena 2 PPA under which it agreed to pay a termination fee of approximately $5 million which were recorded under Selling and marketing expenses in 2018. In 2017 and 2016, no termination fees were incurred.

Warranty on products sold

The Company generally provides a one to two years warranty against defects in workmanship and materials related to the sale of products for electricity generation. The Company considered the warranty as an assurance type warranty since the warranty provides the customer the assurance that the product complies with agreed-upon specifications. Estimated future warranty obligations are included in operating expenses in the period in which the related revenue is recognized. Such charges are immaterial for the years ended December 31, 2018, 2017, and 2016.

Research and development

Research and development costs incurred by the Company for the development of existing and new geothermal, recovered energy and remote power technologies are expensed as incurred. Grants received from the DOE are offset against the related research and development expenses. There were no such grants for the years ended December 31, 2018, 2017, and 2016.

Stock-based compensation

The Company accounts for stock-based compensation using the fair value method whereby compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite employee service period (generally the vesting period of the grant). Starting in 2016, the Company uses the Exercise Multiple-Based Lattice SAR-Pricing Model to value the stock-based compensation awards to reflect accumulated historic data retained of behavioral parameters. Prior to 2016, the Company used the Black-Scholes formula to estimate the fair value of the stock-based compensation.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Tax monetization Transactions

The Company has two tax monetization transactions, Opal Geo and Tungsten as further described under Note 13 – tax monetization transactions to the consolidated financial statements. The OPC and ORTP tax monetization transactions closed during 2017 upon the Company's partners reaching their target after-tax yield on their investment, as further described in Note 13. The purpose of these transactions is to form tax partnerships, whereby investors provide cash in exchange for equity interests that provide the holder a right to the majority of tax benefits associated with a renewable energy project. We account for a portion of the proceeds from the transaction as debt under ASC 470. Given that a portion of these transactions is structured as a purchase of an equity interest we also classify a portion as noncontrolling interest consistent with guidance in ASC 810. The portion recorded to noncontrolling interest is initially measured as the fair value of the discounted Tax Attributes and cash distributions which represents the partner's residual economic interest. The residual proceeds are recognized as the initial carrying value of the debt which is classified as a liability associated with sale tax benefits. We apply the effective interest rate method to the liability associated with the tax monetization transaction component as described by ASC 835 and CON 7. The tax benefits and cash distributions realized by the partner each period are treated as the debt servicing amounts, giving rise to income attributable to the sale of tax benefits. The deferred transaction costs have been capitalized and amortized using the effective interest method.

Income taxes

Income taxes are accounted for using the asset and liability approach, which requires the recognition of taxes payable or refundable for the current year and deferred tax assets and liabilities for the future tax consequences of events that have been recognized in the Company's financial statements or tax returns. The measurement of current and deferred tax assets and liabilities are based on provisions of the enacted tax law. On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Act. The Tax Act makes broad and complex changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35 percent to 21 percent; (2) requiring companies to include in taxable income an amount on certain repatriated earnings of foreign subsidiaries; (3) generally eliminating U.S. federal income taxes on dividends from foreign subsidiaries; (4) requiring a current inclusion in U.S. federal taxable income of certain earnings of controlled foreign corporations (GILTI); (5) eliminating the corporate alternative minimum tax (AMT) and changing how existing AMT credits can be realized; (6) creating BEAT, a new minimum tax; (7) creating a new limitation on deductible interest expense; and (8) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. See Note 18 to the consolidated financial statements for further details regarding the Company's income tax provision and the Tax Act. The Company accounts for investment tax credits and production tax credits as a reduction to income taxes in the year in which the credit arises. The measurement of deferred tax assets is reduced, if necessary, by the amount of any tax benefits that, based on available evidence, are more likely than not expected to be realized. A partial valuation allowance has been established to offset the Company's U.S. deferred tax assets. Tax benefits from uncertain tax positions are recognized only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. Interest and penalties assessed by taxing authorities on an underpayment of income taxes are included as a component of income tax provision in the consolidated statements of operations and comprehensive income.

Earnings per share

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

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

	Year Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Weighted average number of shares used in computation of basic earnings per share	50,643	50,110	49,469
Add:			
Additional shares from the assumed exercise of employee stock options	326	659	671
Weighted average number of shares used in computation of diluted earnings per share	50,969	50,769	50,140

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The number of stock-based awards that could potentially dilute future earnings per share and were not included in the computation of diluted earnings per share because to do so would have been anti-dilutive was 176.4 thousand, 42.9 thousand, and 102.8 thousand, respectively, for the years ended December 31, 2018, 2017, and 2016.

Use of estimates in preparation of financial statements

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the dates of such financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. The most significant estimates with regard to the Company’s consolidated financial statements relate to the useful lives of property, plant and equipment, impairment of goodwill and long-lived assets, including intangible assets, revenue recognition of product sales using the percentage of completion method, asset retirement obligations, and the provision for income taxes.

Puna Power Plant

On May 3, 2018, the Kilauea volcano located in close proximity to our Puna 38 MW geothermal power plant in the Puna district of Hawaii's Big Island erupted following a significant increase in seismic activity in the area. Before it recently stopped flowing, the lava covered the wellheads of three geothermal wells, monitoring wells and the substation of the Puna complex and an adjacent warehouse that stored a drilling rig that was also consumed by the lava. The insurance policy coverage for property and business interruption is provided by a consortium of insurers. All the insurers accepted and started paying for the costs to rebuild the destroyed substation, and as of December 31, 2018 we received $3.3 million. However only some of the insurers accepted that the business interruption coverage started in May 2018 and as of December 31, 2018 we recorded $12.1 million of such proceeds. The Company is still in discussions to reach an understanding with all insurers to start paying for the business interruption as of May 2018. The Company is still assessing the damages in the Puna facilities and continue to coordinate with HELCO and local authorities to bring the power plant back to operation. The Company continues to assess the accounting implications of this event on the assets and liabilities on its balance sheet and whether an impairment will be required. Any significant physical damage to the geothermal resource or continued shut-down following the recent stop of the lava of the Puna facilities could have an adverse impact on the power plant's electricity generation and availability, which in turn could have a material adverse impact on our business and results of operations.

New Accounting Pronouncements

New accounting pronouncements effective in the year ended December 31, 2018

Income Taxes

In March 2018, the Financial Accounting Standards Board ("FASB") issued ASU 2018-05, Income Taxes (Topic 740). The amendments in this update add several SEC paragraphs pursuant to the issuance of the SEC Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (“SAB 118”) in December 2017. The amendments in this update are effective immediately. For additional information, see in Note 18 to our consolidated financial statements set forth in Item 8 of this annual report.

Revenues from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, Revenues from Contracts with Customers, Topic 606, which was a joint project of the FASB and the International Accounting Standards Board to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and International Financial Reporting Standards. The update provides that an entity should recognize revenue in connection with the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Specifically, an entity is required to apply each of the following steps: (1) identify the contract(s) with the customer; (2) identify the performance obligations in the contracts; (3) determine the transaction price; (4) allocate the transaction price to the performance obligation in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 also prescribes additional financial presentations and disclosures. In March 2016, the FASB issued ASU 2016-08, Principal versus Agent Considerations. This update did not change the core principles of the guidance and was intended to clarify the implementation guidance on principal versus agent considerations. When another entity is involved in providing goods or services to a customer, an entity is required to determine if the nature of its promise is to provide the specific good or service itself (that is, the entity is a principal) or to arrange for that good or service to be provided by the other party (that is, the entity is an agent). The guidance included indicators to assist an entity in determining whether it acts as a principal or agent in a specified transaction.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company adopted this update effectively as of January 1, 2018 using the modified retrospective approach with a one-time cumulative adjustment to the opening balance of retained earnings as further described below and applied the five-step model described above on identified outstanding contracts at the date of adoption, under which revenues are generated. Under ASC 606, an entity must identify the performance obligations in a contract, determine the transaction price and allocate the price to specific performance obligations and recognize the revenue when the obligation is completed. A performance obligation is a promise in a contract to transfer a distinct good or service to the customer. A contract’s transaction price is allocated to each distinct performance obligation and recognized as revenue when, or as, the performance obligation is satisfied. The standard also requires disclosure of sufficient information to allow users to understand the nature, amount, timing and uncertainty of revenue and cash flow arising from contracts.

The adoption of ASC 606, Revenues from Contracts with Customers, as described above, did not have an impact on our Electricity, Product and Other segment revenues in 2018, however, the adoption did have an impact on our accounting for our investment in an unconsolidated company as further described in the following table and in the disclosure under the heading "Investment in an unconsolidated company" within this note below. Additionally, the following table below summarizes the impact of the adoption of ASC 606 on the Company’s consolidated financial statements as of January 1, 2018, followed by further information for each of the line items in the table:

	(Dollars in millions)
Electricity segment revenues	$ –
Product segment revenues	–
Other segment revenues	–
Investment in an unconsolidated company as of January 1, 2018	24.0

For a detailed description of our Electricity, Products and Other revenues, please see “Revenues and cost of revenues” caption above.

Contract Assets and Liabilities related to our Product segment: Contract assets reflect revenue recognized and performance obligations satisfied in advance of customer billing. Contract liabilities relate to payments received in advance of the satisfaction of performance under the contract. We receive payments from customers based on the terms established in our contracts. Total contract assets and contract liabilities as of December 31, 2018 and December 31, 2017 are as follows:

	December 31, 2018	**December 31, 2017**
	(Dollars in thousands)	
Contract assets (*)	$42,130	$40,945
Contract liabilities (*)	(18,402)	(20,241)
Contract assets, net	$23,728	$20,704

(*) Contract assets and contract liabilities are presented as "Costs and estimated earnings in excess of billings on uncompleted contracts" and "Billings in excess of costs and estimated earnings on uncompleted contracts", respectively, on the consolidated balance sheet.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the significant changes in the contract assets and contract liabilities for the year ended December 31, 2018:

	Contract assets (Dollars in thousands)	**Contract liabilities**
Recognition of contract liabilities as revenue as a result of performance obligations satisfied	$ -	$ 33,349
Cash received in advance for which revenues have not yet recognized, net expenditures made	-	(38,162)
Reduction of contract assets as a result of rights to consideration becoming unconditional	(128,659)	-
Contract assets recognized, net of recognized receivables	136,496	-
Net change in contract assets and contract liabilities	7,837	(4,813)

The timing of revenue recognition, billings and cash collections results in accounts receivable, contract assets and contract liabilities on the consolidated balance sheet. In our Products segment, amounts are billed as work progresses in accordance with agreed-upon contractual terms, or upon achievement of contractual milestones. Generally, billing occurs subsequent to the recognition of revenue, resulting in contract assets. However, we sometimes receive advances or deposits from our customers before revenue can be recognized, resulting in contract liabilities. These assets and liabilities are reported on the consolidated balance sheet on a contract-by-contract basis at the end of each reporting period. The timing of billing our customers and receiving advance payments vary from contract to contract. The majority of payments are received no later than the completion of the project and satisfaction of our performance obligation.

On December 31, 2018, we had approximately $188.1 million of remaining performance obligations not yet satisfied or partly satisfied related to our Product segment. We expect to recognize approximately 100% of this amount as Product revenues during the next 24 months.

The following schedule reconciles revenues accounted for under ASC 840, Leases, and ASC 606, Revenues from Contracts with Customers, to total consolidated revenues for the year ended December 31, 2018:

	Year Ended December 31, 2018 (Dollars in thousands)
Electricity Revenues accounted under ASC 840, Leases	$ 481,619
Electricity, Product and Other revenues accounted under ASC 606	237,648
Total consolidated revenues	$ 719,267

Disaggregated revenues from contracts with customers for the year ended December 31, 2018 are disclosed under Note 19 – Business Segments, to the consolidated financial statements.

Investment in an unconsolidated company: The Company also reviewed the impact of the adoption of ASC 606 on its investment in an unconsolidated company. As a result of the adoption, the Company recorded a *one*-time cumulative credit adjustment to the opening balance of retained earnings of approximately *$24.0* million as of *January 1, 2018.* This impact is a result of the unconsolidated company's variable consideration related to the construction of its power plant for which, under the new guidance, is probable that a significant reversal in the amount of cumulative revenue recognized will *not* occur when the uncertainty is resolved. As such, the comparative information will *not* be restated and shall continue to be reported under the accounting standards in effect for those periods.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following schedule quantifies the impact of adopting ASC 606 on the statement of operations for the year ended December 31, 2018:

	Year ended December 31, 2018 under previous standard	**Effect of the New Revenue Standard**	**As reported for the year ended December 31, 2018**
	(Dollars in thousands)		
Equity in earnings (losses) of investees, net	$5,615	$ 2,048	$7,663
Income from continuing operations	108,063	2,048	110,111
Net income attributable to the Company's stockholders	95,918	2,048	97,966
Retained earnings as of the end of the period	420,174	2,048	422,222

Compensation - Stock Compensation

In May 2017, the FASB issued ASU 2017-09, Compensation—Stock Compensation (Topic 718). The amendments in this update provide guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting in Topic 718. The amendments in this update require that an entity should account for the effects of a modification unless all of the following are met: (1) The fair value of the modified award is the same as the fair value of the original award immediately before the original award is modified; (2) The vesting conditions of the modified award are the same as the vesting conditions of the original award immediately before the original award is modified; (3) The classification of the modified award as an equity instrument or a liability instrument is the same as the classification of the original award immediately before the original award is modified. The current disclosure requirements under Topic 718 apply regardless of whether an entity is required to apply modification accounting under the amendments in this update. The amendments in this update are effective for all entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. The amendments in this update should be applied prospectively to an award modified on or after the adoption date. The adoption of this guidance did not have a material impact on the Company's consolidated financial statements.

Business Combinations

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805). The update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The amendments in this update primarily provide a screen to determine when a set of assets and activities is not a business and by that reduces the number of transactions that need to be further evaluated. The amendments in this update should be applied prospectively and are effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The adoption of this guidance did not have an impact on the Company's condensed consolidated financial statements.

Statement of Cash Flow

In November 2016, the FASB issued ASU 2016-18, Statement of Cash Flows (Topic 230) – Restricted Cash. The amendments in this update require that a statement of cash flows explain the changes during the period in total cash, cash equivalents, and the amounts generally described as restricted cash or cash equivalents. Therefore, amounts of restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. The amendments in this update should be applied retrospectively for each period presented and are effective for financial statements issued for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. The Company adopted this guidance retrospectively in its consolidated financial statements for the year ended December 31, 2018 and adjusted its disclosure accordingly.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Intra-Entity Transfers of Assets Other than Inventory

In October 2016, the FASB issued ASU 2016-16, Accounting for Income Taxes: Intra-Entity Asset Transfers of Assets Other than Inventory. The amendments in this update require that the entity would recognize the tax expense from the sale of the asset in the seller's tax jurisdiction when the transfer occurs, even though the pre-tax effects of that transaction are eliminated in consolidation. Any deferred tax asset that arises in the buyer's jurisdiction would also be recognized at the time of the transfer. The new guidance does not apply to intra-entity transfers on inventory. The amendments in this update should be applied for each period presented and are effective for financial statements issued for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. The modified retrospective approach is required for transition to the new guidance, with cumulative-effect adjustment recorded in retained earnings as of the beginning of the period of adoption. The Company adopted this guidance in its consolidated financial statements for the year ended December 31, 2018 using the modified retrospective approach. As a result, there was an adjustment to deferred charges with a corresponding adjustment to deferred income taxes of $49.8 million with an immaterial amount recorded to retained earnings.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash payments (Topic 230)

In August 2016, the FASB issued ASU 2016-15, Statement of Cash-Flows (Topic 230). This update addresses eight specific cash flow classification issues with the objective of reducing diversity in practice. One of the issues addressed in this update is debt prepayment or debt extinguishment costs which under the new guidance should be classified as cash outflows for financing activities. Additionally, the update addressed contingent consideration payments made after a business combination. Such cash payments made soon after the acquisition date to settle a contingent consideration liability should be classified as cash outflows for investing activities. Payments made thereafter should be classified as cash outflows for financing activities up to the amount of the original contingent consideration liability. Payments made in excess of the amount of the original contingent consideration liability should be classified as cash outflows for operating activities. The amendments in this update are effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. The amendments in this update should be applied using a retrospective transition method to each period presented. The Company adopted this guidance in the year ended December 31, 2018 and accordingly reclassified approximately $8.0 million of cash paid for achievement of certain production thresholds in Guadeloupe during the fourth quarter of 2017 from cash outflows from investing activities to cash outflows from financing activities as required by this update.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities. The update primarily requires that an entity present separately, in other comprehensive income, the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk if the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments. The application of this update should be by means of cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The amendments in this update are effective for financial statements issued for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years. The adoption of this update did not have a material impact on the Company’s consolidated financial statements.

Intangibles –Goodwill and Other

In January 2017, the FASB issued ASU 2017-04, Intangibles – Goodwill and Other (Topic 350). The amendments in this Update require the entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value, however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider the income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. This update, eliminated Step 2 from the goodwill impairment test under the current guidance. Step 2 measures a goodwill impairment loss by comparing the implied fair value of reporting unit’s goodwill with the carrying amount of that goodwill. The amendments in this Update should be applied on a prospective basis. An entity is also required to disclose the nature of and the reason for the change in accounting principal upon transition. That disclosure should be provided in the first annual period and the interim period within the first annual period when the entity initially adopts the amendments in this Update. The amendments in this Update are effective for the annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual impairment tests performed on testing dates after January 1, 2017. The Company adopted this Update in 2018 in connection with its goodwill impairment test of Viridity.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

New accounting pronouncements effective in future periods

Derivatives and Hedging

In August 2017, the FASB issued ASU 2017-12, Targeted Improvements to Accounting for Hedging Activities. The amendments in this Update better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. To meet that objective, the amendments expand and refine hedge accounting for both nonfinancial and financial risk components and align the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The amendments in this Update are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early application is permitted in any interim period after issuance of the Update. The Company is currently evaluating the potential impact, if any, of the adoption of these amendments on its consolidated financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). This update introduces a number of changes and simplifies previous guidance, primarily the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. The update retains the distinction between finance leases and operating leases and the classification criteria between the two types remains substantially similar. Also, lessor accounting remains largely unchanged from previous guidance. However, key aspects of the update were aligned with the revenue recognition guidance in Topic 606. Additionally, the update defines a lease as a contract, or part of a contract, that conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Control over the use of the identified asset means that the customer has both (a) the right to obtain substantially all of the economic benefits from the use of the asset and (b) the right to direct the use of the asset. This update requires the modified retrospective transition approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented. The modified retrospective approach includes a number of optional practical expedients related to identification and classification of leases that commenced before the effective date, initial direct costs for leases that commenced before the effective date and the ability to use hindsight in evaluating lessee options to extend or terminate a lease or to purchase the underlying asset. An entity that elects to apply the practical expedients will, in effect, continue to account for leases that commenced before the effective date in accordance with the previous generally accepted accounting principles in the United States unless the lease is modified, except that lessees are required to recognize a right-of-use asset and a lease liability for all operating leases at each reporting date based on the present value of the remaining minimum rental payments that were tracked and disclosed under previous generally accepted accounting principles in the United States. Since the issuance of the update in February 2016, the FASB issues several additional updates and amendments including ASU 2018-11, Leases, which was issued in July 2018 and provided an additional optional transition method for the adoption of the standard as well as additional codification improvements. Under this new transition method, an entity initially applies the new lease standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, the comparative periods presented in the financial statements in which the standard is adopted will continue to be in accordance with the current GAAP. The amendments in this update are effective for annual reporting periods beginning after December 15, 2018, including interim periods within those reporting periods.

The Company performed an evaluation of the impact from adopting the standard on its financial statements which included, among others, utilization of internal resources to lead the implementation efforts and supplement them with external resources and accounting professionals, review of the Company's existing lease portfolio and assess the impact to its business processes and internal control over financial reporting. The Company will adopt this update on January 1, 2019, using the modified retrospective approach at the effective date with no adjustment to the comparative periods which will continue to be presented in accordance with the current GAAP. Additionally, the Company expects to elect the above-mentioned practical expedients as provided by the new standard and consequently will not recognize right-of-use assets and lease liabilities for arrangements with a term of less than one year and not separate lease and non-lease components for all classes of underlying assets other than real estate assets. The Company also expects to apply the portfolio approach under the update, primarily with respect to determination of incremental borrowing rate.

The Company has substantially completed its assessment of the potential impact that the implementation of this update will have on its consolidated financial statements and continues to finalize its efforts relative to the adoption of this update as of January 1, 2019. While our current evaluation and conclusions are subject to changes as our assessment has not yet been completed, the Company expects there will be an increase to assets and liabilities related to the recognition of a right-of-use asset and a lease liability on its existing lease portfolio in the amount within a range between approximately $27.0 million and $30.0 million, however, it does not expect the adoption of the update to have a material impact on its consolidated statement of operations and comprehensive income and consolidated statements of cash flows.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive income

In February 2018, the FASB issued ASU 2018-02, Income Statement – Reporting Comprehensive Income (Topic 220). The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting for the Tax Act. The guidance is effective for the fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted. The Company is currently evaluating the potential impact of the adoption of these amendments on its consolidated financial statements, however, such impact, if any, is not expected to be material.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1(a) - Retrospective adjustments as a result of adoption of accounting policies and change in segments

As described above in Note 1, the Company adopted ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments and ASU 2016-18, Statement of Cash Flow that required retrospective adjustments to the years ended December 31, 2017 and 2016 to the Statement of Cash Flows. Further, as described in Note 19, in 2018, the Company started disclosing its energy storage and power load management business activity under the Other segment as such operations met the reportable segment criteria of ASC 280, Segment Reporting. This separate reportable segment required retrospective adjustment for comparative purposes for the year ended December 31, 2017.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 2 —BUSINESS ACQUISITIONS AND OTHERS

USG transaction

On April 24, 2018, the Company completed the acquisition of USG. The total cash consideration (exclusive of transaction expenses) was approximately $110 million, comprised of approximately $106 million funded from available cash of Ormat Nevada Inc. (to acquire the outstanding shares of common stock of USG) and approximately $4 million funded from available cash of USG (to cash-settle outstanding in-the-money options for common stock of USG). As a result of the acquisition, USG became an indirect wholly owned subsidiary of Ormat, and Ormat indirectly acquired, among other things, interests held by USG and its subsidiaries in:

- three operating power plants at Neal Hot Springs, Oregon; San Emidio, Nevada; and Raft River, Idaho with a total net generating capacity of approximately 38 MW; and
- development assets which include a project at the Geysers, California; a second phase project at San Emidio, Nevada; a greenfield project in Crescent Valley, Nevada; and the El Ceibillo project located near Guatemala City, Guatemala.

As a result of the acquisition, the Company expanded its overall generation capacity and expects to improve the profitability of the purchased assets through cost reduction and synergies. The Company accounted for the transaction in accordance with Accounting Standard Codification ASC 805, Business Combinations and following the transaction, the Company consolidates USG, in accordance with Accounting Standard Codification ASC 810, Consolidation. Accounting guidance provides that the allocation of the purchase price may be modified for up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. The Company deemed that the adoption of ASU 2017-01, Business Combinations, as further described under Note 1 to the consolidated financial statements, did not have an effect on the USG transaction.

The following table summarizes the purchase price allocation to the fair value of the assets acquired and liabilities assumed (in millions):

Cash and cash equivalents and restricted cash	$37.9
Property, plant and equipment and construction-in-process	77.3
Intangible assets [(1)]	127.0
Goodwill [(2)]	12.7
Deferred taxes	1.7
Total assets acquired	$256.6
Other working capital	$(8.2)
Long-term term debt	(98.3)
Asset retirement obligation	(9.0)
Noncontrolling interest	(34.9)
Total liabilities assumed	$(150.4)
Total assets acquired, and liabilities assumed, net	$106.2

(1) Intangible assets are primarily related to long-term electricity power purchase agreements and depreciated over an average of 19 years.

(2) Goodwill is primarily related to the expected synergies in operations as a result of the purchase transaction. The goodwill is allocated to the Electricity segment and not deductible for tax purposes.

The fair value of the noncontrolling interest of $34.9 million reflects the 40% minority interests in the Neal Hot Springs project that was evaluated using the income approach. The fair value of the noncontrolling interest is based on the following significant inputs: (i) forecasted cash flows assumed to be generated in correspondence with the remaining life of the related power purchase agreement which is approximately 20 years; (ii) revenues were estimated in accordance with the price and generation capacity of the related power purchase agreement; (iii) assumed terminal value based on the realizable value of the project at the end of the power purchase agreement term; and (iv) assumed discount rate of approximately 9%.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Total Electricity revenues and operating profit related to the three USG power plants of approximately $21.4 million and $2.5 million, respectively, for the period started at the acquisition date to December 31, 2018 were included in the Company's consolidated statements of operations and comprehensive income for the year ended December 31, 2018. The following unaudited pro forma summary presents consolidated information of the Company as if the business combination had occurred on January 1, 2017:

	Pro forma for the year ended December 31, 2018	Pro forma for the year ended December 31, 2017
	(Dollars in thousands)	
Electricity revenues	$521,175	$497,650
Total revenues	730,563	724,869
Income from continuing operations before income taxes and equity in losses of investees	134,142	169,546

Viridity transaction

On March 15, 2017, the Company completed the acquisition of substantially all of the business and assets of Viridity Energy, Inc., a privately held Philadelphia-based company formerly engaged in the provision of demand response, energy management and energy storage services. At closing, Viridity Energy Solutions Inc. ("Viridity"), a wholly owned subsidiary of the Company, paid initial consideration of $35.3 million. Additional contingent consideration with an estimated fair value of $12.4 million was set upon the achievement of certain performance milestones to be measured at the end of fiscal years 2017 and 2020. The first performance milestone measured at the end of 2017 was not achieved and as a result, the Company reversed the related contingent consideration in the amount of $0.6 million which was recorded under general and administrative expenses. Additionally, as of December 31, 2018, the Company estimated that the second milestone to be measured at the end of fiscal year 2020 will not be achieved and consequently reversed the related contingent consideration in the amount of $10.3 million. The reversal of the contingent liability was recorded under general and administrative expenses for the year ended December 31, 2018.

Using proprietary software and solutions, Viridity serves primarily retail energy providers, utilities, and large commercial and industrial customers. Viridity’s offerings enable its customers to optimize and monetize their energy management, demand response and storage facilities potential by interacting on their behalf with regional transmission organizations and independent system operators.

The Company accounted for the transaction in accordance with Accounting Standard Codification 805, Business Combinations, and consequently recorded intangible assets of $34.7 million primarily relating to Viridity’s storage activities with a weighted-average amortization period of 19 years, approximately $0.4 million of working capital and fixed assets and $13.5 million of goodwill. Following the transaction, the Company consolidated Viridity in accordance with Accounting Standard Codification 810, Consolidation. The acquisition enabled the Company to enter the growing energy storage and demand response markets and expand its market presence.

During the fourth quarter of 2018, the Company recorded an impairment charge for the full amount of goodwill associated with its storage and energy management services in its consolidated statements of operations and comprehensive income (loss). Further information related to this impairment charge is disclosed in Note 9 – “Intangible assets and goodwill” to the consolidated financial statements.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 3 — INVENTORIES

Inventories consist of the following:

	December 31,	
	2018	2017
	(Dollars in thousands)	
Raw materials and purchased parts for assembly	$26,914	$12,007
Self-manufactured assembly parts and finished products	18,110	7,544
Total	$45,024	$19,551

NOTE 4 — COST AND ESTIMATED EARNINGS ON UNCOMPLETED CONTRACTS

Cost and estimated earnings on uncompleted contracts consist of the following:

	December 31,	
	2018	2017
	(Dollars in thousands)	
Costs and estimated earnings incurred on uncompleted contracts	$278,797	$550,823
Less billings to date	(255,069)	(530,119)
Total	$23,728	$20,704

These amounts are included in the consolidated balance sheets under the following captions:

	December 31, 2018	2017
	(Dollars in thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$42,130	$40,945
Billings in excess of costs and estimated earnings on uncompleted contracts	(18,402)	(20,241)
Total	$23,728	$20,704

The completion costs of the Company’s construction contracts are subject to estimation. Due to uncertainties inherent in the estimation process, it is reasonably possible that estimated contract earnings will be further revised in the near term.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 5 — Investment in an unconsolidated company

Investment in an unconsolidated company mainly consist of the following:

	December 31,	
	2018	2017
	(Dollars in thousands)	
Sarulla	$71,983	$34,084

The Sarulla Project

The Company holds a 12.75% equity interest in a consortium that developed the 330 MW Sarulla geothermal power plant project in Tapanuli Utara, North Sumatra, Indonesia. The Sarulla project is comprised of three separately constructed 110 MW units, the most recent of which, NIL 2, was completed in April 2018. The Sarulla project is owned and operated by the consortium members under the framework of a joint operating contract and energy sales contract that were both executed on April 4, 2013. Under the joint operating contract, PT Pertamina Geothermal Energy, the concession holder for the project, provided the consortium with the right to use the geothermal field, and under the energy sales contract, PT PLN, the state electric utility, is the off-taker at Sarulla for a period of 30 years.

During the years ended December 31, 2018 and 2017, the Company made additional cash equity investments in the Sarulla project of approximately $3.8 million and $46.3 million, respectively, for a total of $62.0 million since inception.

The Sarulla consortium entered into interest rate swap agreements with various international banks, effective as of June 4, 2014, and accounted for the interest rate swap as a cash flow hedge upon which changes in the fair value of the hedging instrument, relative to the effective portion, are recorded in other comprehensive income. The Company's share of such gains (losses) recorded in other comprehensive income (loss) are as follows:

	Year Ended December 31,	
	2018	2017
	(Dollars in thousands)	
Change, net of deferred tax, in unrealized gains (losses) in respect of the Company's share in derivative instruments of unconsolidated investment	$2,235	$804

The related accumulated loss recorded by the Company in other comprehensive income (loss) as of December 31, 2018 is $2.9 million.

As further described above under Note 1 to the consolidated financial statements under the heading "New accounting pronouncement effective in the year ended December 31, 2018", the Company adopted ASC 606, Revenue from Contracts with Customers, on January 1, 2018. The impact of the adoption of this standard on its investment in an unconsolidated company amounted to $24.0 million at January 1, 2018. This impact was a result of the unconsolidated company's variable consideration related to the construction of its power plant for which, under the new guidance, is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty is resolved. The Company adopted the new standard using the modified retrospective approach with a one-time cumulative adjustment to the opening balance of retained earnings of approximately $24.0 million at January 1, 2018, the date of initial application.

NOTE 6 — VARIABLE INTEREST ENTITIES

The Company's overall methodology for evaluating transactions and relationships under the variable interest entity ("VIE") accounting and disclosure requirements includes the following two steps: (i) determining whether the entity meets the criteria to qualify as a VIE; and (ii) determining whether the Company is the primary beneficiary of the VIE.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In performing the first step, the significant factors and judgments that the Company considers in making the determination as to whether an entity is a VIE include:

- The design of the entity, including the nature of its risks and the purpose for which the entity was created, to determine the variability that the entity was designed to create and distribute to its interest holders;
- The nature of the Company's involvement with the entity;
- Whether control of the entity may be achieved through arrangements that do not involve voting equity;
- Whether there is sufficient equity investment at risk to finance the activities of the entity; and
- Whether parties other than the equity holders have the obligation to absorb expected losses or the right to receive residual returns.

If the Company identifies a VIE based on the above considerations, it then performs the second step and evaluates whether it is the primary beneficiary of the VIE by considering the following significant factors and judgments:

- Whether the Company has the power to direct the activities of the VIE that most significantly impact the entity's economic performance; and
- Whether the Company has the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The Company's VIEs include certain of its wholly owned subsidiaries that own one or more power plants with long-term PPAs. In most cases, the PPAs require the utility to purchase substantially all of the plant's electrical output over a significant portion of its estimated useful life. Most of the VIEs have associated project financing debt that is non-recourse to the general creditors of the Company, is collateralized by substantially all of the assets of the VIE and those of its wholly owned subsidiaries (also VIEs) and is fully and unconditionally guaranteed by such subsidiaries.

The Company has concluded that such entities are VIEs primarily because the entities do not have sufficient equity at risk and/or subordinated financial support is provided through the long-term PPAs. The Company has evaluated each of its VIEs to determine the primary beneficiary by considering the party that has the power to direct the most significant activities of the entity. Such activities include, among others, construction of the power plant, operations and maintenance, dispatch of electricity, financing and strategy. Except for power plants that it acquired, the Company is responsible for the construction of its power plants and generally provides operation and maintenance services. Primarily due to its involvement in these and other activities, the Company has concluded that it directs the most significant activities at each of its VIEs and, therefore, is considered the primary beneficiary. The Company performs an ongoing reassessment of the VIEs to determine the primary beneficiary and may be required to deconsolidate certain of its VIEs in the future. The Company has aggregated its consolidated VIEs into the following categories: (i) wholly owned subsidiaries with project debt; and (ii) wholly owned subsidiaries with PPAs.

The tables below detail the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for the Company's VIEs, combined by VIE classifications, that were included in the consolidated balance sheets as of December 31, 2018 and 2017:

	December 31, 2018	
	Project Debt	**PPAs**
	(Dollars in thousands)	
Assets:		
Restricted cash and cash equivalents	$76,019	$2,304
Other current assets	213,007	9,698
Property, plant and equipment, net	1,552,408	306,820
Construction-in-process	90,812	13,273
Other long-term assets	177,723	9,104
Total assets	$2,109,969	$341,199
Liabilities:		
Accounts payable and accrued expenses	$24,245	$2,651
Long-term debt	805,850	—
Other long-term liabilities	125,769	12,483
Total liabilities	$955,864	$15,134

158

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2017	
	Project Debt	PPAs
	(Dollars in thousands)	
Assets:		
Restricted cash, cash equivalents and marketable securities	$48,676	$—
Other current assets	124,322	18,010
Property, plant and equipment, net	1,252,623	379,277
Construction-in-process	129,832	12,885
Other long-term assets	63,667	276
Total assets	$1,619,120	$410,448
Liabilities:		
Accounts payable and accrued expenses	$24,887	$6,863
Long-term debt	658,726	—
Other long-term liabilities	93,682	6,757
Total liabilities	$777,295	$13,620

NOTE 7— FAIR VALUE OF FINANCIAL INSTRUMENTS

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

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

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

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

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth certain fair value information at December 31, 2018 and 2017 for financial assets and liabilities measured at fair value by level within the fair value hierarchy, as well as cost or amortized cost. As required by the fair value measurement guidance, assets and liabilities are classified in their entirety based on the lowest level of inputs that is significant to the fair value measurement.

		December 31, 2018 Fair Value			
	Carrying Value at December 31, 2018	Total	Level 1	Level 2	Level 3
	(Dollars in thousands)				
Assets:					
Current assets:					
Cash equivalents (including restricted cash accounts)	$18,787	$18,787	$18,787	$—	$—
Derivatives:					
Contingent receivable [(1)]	104	104	—	—	104
Liabilities:					
Current liabilities:					
Derivatives:					
Contingent payables [(1)]	(3,424)	(3,424)	—	—	(3,424)
Currency forward contracts [(2)]	(1,040)	(1,040)	—	(1,040)	—
	$14,427	$14,427	$18,787	$(1,040)	$(3,320)

		December 31, 2017 Fair Value			
	Carrying Value at December	Total	Level 1	Level 2	Level 3

	31, 2017 (Dollars in thousands)				
Assets					
Current assets:					
Cash equivalents (including restricted cash accounts)	$18,359	$18,359	$18,359	$—	$—
Derivatives:					
Contingent receivable (1)	108	108	—	—	108
Currency forward contracts (2)	992	992	—	992	—
Liabilities:					
Current liabilities:					
Derivatives:					
Contingent payables (1)	(13,904)	(13,904)	—	—	(13,904)
Warrants (1)	(3,967)	(3,967)	—	—	(3,967)
	$1,588	$1,588	$18,359	$992	$(17,763)

(1) These amounts relate to contingent receivables and payables and warrants pertaining to the Viridity acquisition and Guadeloupe power plant purchase transaction, valued primarily based on unobservable inputs and are included within "Prepaid expenses and other", "Accounts Payable and accrued expenses" and "Other long-term liabilities" on December 31, 2018 and 2017 in the consolidated balance sheets with the corresponding gain or loss being recognized within "Derivatives and foreign currency transaction gains (losses)" in the consolidated statement of operations and comprehensive income.

(2) These amounts relate to currency forward contracts valued primarily based on observable inputs, including forward and spot prices for currencies, net of contracted rates and then multiplied by notional amounts, and are included within "Prepaid expenses and other" and "Accounts payable and accrued expenses", as applicable, on December 31, 2018 and December 31, 2017, in the consolidated balance sheet with the corresponding gain or loss being recognized within "Derivatives and foreign currency transaction gains (losses)" in the consolidated statement of operations and comprehensive income.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

Derivatives not designated as hedging instruments	**Location of recognized gain (loss)**	**Amount of recognized gain (loss)**		
		2018	**2017**	**2016**
		(Dollars in thousands)		
Put options on natural gas price	Derivative and foreign currency transaction gains (losses)	$—	$(350)	$—
Call options on natural gas price	Derivative and foreign currency transaction gains (losses)	—	—	(1,340)
Call and put options on oil price	Derivative and foreign currency transaction gains (losses)	—	—	(1,313)
Contingent considerations	Derivative and foreign currency transaction gains (losses)	170	(129)	(1,527)
Contingent considerations	General and administrative expenses	10,322	2,048	—
Currency forward contracts	Derivative and foreign currency transaction gains (losses)	(3,081)	3,699	238
		$7,411	$5,268	$(3,942)

In January 2017, the Company entered into Henry Hub Natural Gas Future contracts under which it has bought a number of put options covering a notional quantity of approximately 4.1 million British Thermal Units ("MMBtu") with exercise prices of $3 and expiration dates ranging from January 26, 2017 until November 27, 2017 in order to reduce its exposure to fluctuations in natural gas prices under its PPAs with Southern California Edison. The Company paid an aggregate amount of approximately $0.7 million for these put options. The put option contracts have monthly expiration dates at which the options can be called and the transaction would be settled on a net cash basis.

On February 2, 2016, the Company entered into Henry Hub Natural Gas Future contracts under which it has written a number of call options covering a notional quantity of approximately 4.1 MMBtu with exercise prices of $2 and expiration dates ranging from February 24, 2016 until December 27, 2016 in order to reduce its exposure to fluctuations in natural gas prices under its PPAs with Southern California Edison. The Company received an aggregate premium of approximately $1.9 million from these call options. The call option contracts have monthly expiration dates at which the options can be called and the Company would have to settle its liability on a cash basis.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On February 24, 2016, the Company entered into Brent Oil Future contracts under which it has written a number of call options covering a notional quantity of approximately 185,000 barrels (“BBL”) of Brent with exercise prices of $32.80 to $35.50 and expiration dates ranging from March 24, 2016 until December 22, 2016 in order to reduce its exposure to fluctuations in Brent prices under its PPA with HELCO. The Company received an aggregate premium of approximately $1.1 million from these call options. The call option contracts have monthly expiration dates whereby the options can be called and the Company would have to settle its liability on a cash basis. Moreover, during March 2016, the Company rolled 2 existing call options covering a total notional quantity of 31,800 BBL of Brent in order to limit its exposure to $41 to $42.50 instead of $32.80 to $33.50. In addition, the Company entered into short risk reversal transactions (sell call and buy put options) by rolling existing call options covering notional quantities of 16,500 BBL and 17,000 BBL in order to limit its exposure from the outstanding call options originally entered into in February 2016 to a range of $28.50 to $37.50 and $28 to $38.50, respectively.

The foregoing future, forward and swap transactions have not been designated as hedge transactions and are marked to market with the corresponding gains or losses recognized within “Derivatives and foreign currency transaction gains (losses)” in the consolidated statements of operations and comprehensive income.

There were no transfers of assets or liabilities between Level 1, Level 2 and Level 3 during the year ended December 31, 2018.

The fair value of the Company’s long-term debt is as follows:

	Fair Value		**Carrying Amount**	
	2018	**2017**	**2018**	**2017**
	(Dollars in millions)		**(Dollars in millions)**	
Olkaria III Loan - OPIC	211.8	234.6	210.6	228.6
Olkaria IV Loan - DEG 2	47.2	50.7	47.5	50.0
Platanares Loan - OPIC	119.1	—	112.7	—
Amatitlan Loan	29.9	32.8	29.8	33.3
Senior Secured Notes:				
OrCal Geothermal Inc. ("OrCal")	19.0	34.2	18.7	32.1

OFC 2 LLC ("OFC 2")	214.5	234.6	217.8	232.5
Don A. Campbell 1 ("DAC 1")	78.8	85.5	83.3	88.3
USG Prudential - NV	29.4	—	27.8	—
USG Prudential - ID	18.6	—	18.9	—
USG DOE	48.3	—	51.4	—
Senior Unsecured Bonds	199.4	200.3	204.3	204.3
Senior Unsecured Loan	102.2	—	100.0	—
Other long-term debt	5.4	7.0	6.2	7.9

The fair value of the long-term debt is determined by a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of current borrowing rates.The fair value of revolving lines of credit is determined using a comparison of market-based price sources that are reflective of similar credit ratings to those of the Company.

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

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value of financial instruments as of December 31, 2018:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III - OPIC	—	—	211.8	211.8
Olkaria IV - DEG 2	—	—	47.2	47.2
Platanares Loan - OPIC	—	—	119.1	119.1
Amatitlan Loan	—	29.9	—	29.9
Senior Secured Notes:				
OrCal Senior Secured Notes	—	—	19.0	19.0
OFC 2 Senior Secured Notes	—	—	214.5	214.5
DAC 1 Senior Secured Notes	—	—	78.8	78.8
USG Prudential - NV	—	—	29.4	29.4
USG Prudential - ID	—	—	18.6	18.6
USG DOE	—	—	48.3	48.3
Senior Unsecured Bonds	—	—	199.4	199.4
Senior Unsecured Loan	—	—	102.2	102.2
Other long-term debt	—	—	5.4	5.4
Revolving lines of credit	—	159.0	—	159.0
Deposits	12.0	—	—	12.0

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the fair value of financial instruments as of December 31, 2017:

	Level 1	Level 2	Level 3	Total
	(Dollars in millions)			
Olkaria III Loan - OPIC	$—	$—	$234.6	$234.6
Olkaria IV - DEG 2			50.7	50.7
Amatitlan Loan	—	32.8	—	32.8
Senior Secured Notes:				
OrCal Senior Secured Notes	—	—	34.2	34.2
OFC 2 Senior Secured Notes	—	—	234.6	234.6
DAC 1 Senior Secured Notes	—	—	85.5	85.5
Senior Unsecured Bonds	—	—	200.3	200.3
Other long-term debt	—	—	7.0	7.0
Revolving lines of credit	—	51.5	—	51.5
Deposits	15.6	—	—	15.6

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 8 — PROPERTY, PLANT AND EQUIPMENT AND CONSTRUCTION-IN-PROCESS

Property, plant and equipment

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

	December 31,	
	2018	2017
	(Dollars in thousands)	
Land owned by the Company where the geothermal resource is located	$38,060	$32,178
Leasehold improvements	5,718	3,984
Machinery and equipment	208,646	182,121
Land, buildings and office equipment	35,708	31,128
Automobiles	22,074	12,596
Geothermal and recovered energy generation power plants, including geothermal wells and exploration and resource development costs:		
United States of America, net of cash grants	2,065,377	1,744,728
Foreign countries	710,775	700,498
Asset retirement cost	11,448	10,563
	3,097,806	2,717,797
Less accumulated depreciation	(1,138,228)	(983,106)
Property, plant and equipment, net	$1,959,578	$1,734,691

Depreciation expense for the years ended December 31, 2018, 2017, and 2016 amounted to $114.4 million, $98.8 million and $94.8 million, respectively. Depreciation expense for the years ended December 31, 2018, 2017 and 2016 is net of the impact of the cash grant in the amount of $6.4 million, $5.5 million and $5.5 million, respectively.

U.S. Operations

The net book value of the property, plant and equipment, including construction-in-process, located in the U.S. was approximately $1,696.4 million and $1,447.4 million as of December 31, 2018 and 2017, respectively. These amounts as of December 31, 2018 and 2017 are net of cash grants in the amount of $179.7 million and $133.2 million, respectively.

Foreign Operations

The net book value of property, plant and equipment, including construction-in-process, located outside of the U.S. was approximately $524.8 million and $580.8 million as of December 31, 2018 and 2017, respectively.

The Company, through its wholly owned subsidiary, OrPower 4, Inc. (“OrPower 4”), owns and operates geothermal power plants in Kenya. The net book value of assets associated with the power plants was $302.0 million and $326.1 million as of December 31, 2018 and 2017, respectively. The Company sells the electricity produced by the power plants to Kenya Power and Lighting Co. Ltd. (“KPLC”) under a 20-year PPA.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company, through its wholly owned subsidiary, Orzunil I de Electricidad, Limitada (“Orzunil”), owns a power plant in Guatemala. On January 22, 2014, Orzunil signed an amendment to the PPA with INDE, a Guatemalan power company, for its Zunil geothermal power plant in Guatemala. The amendment extends the term of the PPA from 2019 to 2034. The PPA amendment also transfers operation and management responsibilities of the Zunil geothermal field from INDE to the Company for the term of the amended PPA in exchange for a tariff increase. Additionally, INDE exercised its right under the PPA to become a partner in the Zunil power plant with a 3% equity interest. The net book value of the assets related to the power plant was $14.6 million and $9.9 million at December 31, 2018 and 2017, respectively.

The Company, through its wholly owned subsidiary, Ortitlan, Limitada (“Ortitlan”), owns a power plant in Guatemala. The net book value of the assets related to the power plant was $43.5 million and $40.7 million at December 31, 2018 and 2017, respectively.

The Company, through its wholly owned subsidiary, GeoPlatanares, signed a BOT contract for the Platanares geothermal project in Honduras with ELCOSA, a privately owned Honduran energy company, for 15 years from the commercial operation date. Platanares sells the electricity produced by the power plants to ENEE, the national utility of Honduras under a 30-year PPA. The net book value of the assets related to the power plant was $105.7 million and $140.3 million at December 31, 2018 and 2017, respectively.

The Company, through its subsidiary, GB, owns a power plant in Guadeloupe. The net book value of the assets related to the power plant was $23.9 million and $24.9 million at December 31, 2018 and 2017, respectively. GB sells the electricity produced by the power plants to EDF, the French electric utility, under a 15-year PPA.

Construction-in-process

Construction-in-process consists of the following:

	December 31, 2018	2017
	(Dollars in thousands)	
Projects under exploration and development:		
Up-front bonus lease costs	$17,018	$17,018
Exploration and development costs	53,237	46,154
Interest capitalized	703	703
	70,958	63,875
Projects under construction:		
Up-front bonus lease costs	27,473	27,473
Drilling and construction costs	160,398	198,943
Interest capitalized	2,861	3,251
	190,732	229,667
Total	$261,690	$293,542

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Projects under Exploration and Development			
	Up-front Bonus Lease Costs	Exploration and Development Costs	Interest Capitalized	Total
	(Dollars in thousands)			
Balance at December 31, 2015	$26,491	$ 35,726	$ 703	$62,920
Cost incurred during the year	1,514	25,165	—	26,679
Write off of unsuccessful exploration costs	(380)	(2,637)	—	(3,017)
Transfer of projects under exploration and development to projects under construction	(10,240)	(21,895)	—	(32,135)
Balance at December 31, 2016	17,385	36,359	703	54,447
Cost incurred during the year	—	11,224	—	11,224
Write off of unsuccessful exploration costs	(367)	(1,429)	—	(1,796)
Balance at December 31, 2017	17,018	46,154	703	63,875
Cost incurred during the year	—	7,209	—	7,209
Write off of unsuccessful exploration costs	—	(126)	—	(126)
Balance at December 31, 2018	$17,018	$ 53,237	$ 703	$70,958

	Projects under Construction			
	Up-front Bonus Lease Costs	Drilling and Construction Costs	Interest Capitalized	Total
	(Dollars in thousands)			
Balance at December 31, 2015	$27,473	$ 150,467	$ 7,975	$185,915
Cost incurred during the year	—	116,247	6,510	122,757
Transfer of projects under exploration and development to projects under construction	10,240	21,895	—	32,135
Transfer of completed projects to property, plant and equipment	—	(86,398)	(2,147)	(88,545)
Balance at December 31, 2016	37,713	202,211	12,338	252,262
Cost incurred during the year	—	231,926	7,300	239,226
Transfer of completed projects to property, plant and equipment	(10,240)	(235,194)	(16,387)	(261,821)
Balance at December 31, 2017	27,473	198,943	3,251	229,667
Cost incurred during the year	—	219,610	—	219,610
Cost write off	—	(1,380)	—	(1,380)
	—	4,668	—	4,668

Fair value of projects under construction acquired in a business combination				
Transfer of completed projects to property, plant and equipment	—	(261,443)	(390)	(261,833)
Balance at December 31, 2018	$27,473	$ 160,398	$ 2,861	$190,732

167

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 9 — INTANGIBLE ASSETS AND GOODWILL

Intangible assets amounting to $199.9 million and $85.4 million consist mainly of the Company's PPAs acquired in business combinations and Viridity's storage activities, net of accumulated amortization of $61.5 million and $50.0 million as of December 31, 2018 and 2017, respectively. Intangible assets relating to our storage activities, as of December 31, 2018 and 2017, amounted to $32.2 million and $33.8 million, net of accumulated amortization of $3.4 million and $1.7 million, respectively. Amortization expense for the years ended December 31, 2018, 2017, and 2016 amounted to $11.2 million, $6.9 million, and $4.4 million, respectively. Additions to intangible assets for the years ended December 31, 2018, 2017 and 2016, amounted to $127.0 million, $35.6 million and $33.0 million, respectively. The additions to intangible assets in 2018, 2017 and 2016 primarily relate to the USG acquisition, Viridity acquisition and the purchase of the Guadeloupe plant, respectively. The Company tested the intangible assets for recoverability in December 2018 and 2017 and assessed whether there are events or change in circumstances which may indicate that the intangible assets are not recoverable. Our assessment resulted in that there were no write-offs of intangible assets in 2018, 2017 and 2016.

Estimated future amortization expense for the intangible assets as of December 31, 2018 is as follows:

	(Dollars in thousands)
Year ending December 31:	
2019	$ 13,422
2020	13,105
2021	13,105
2022	12,850
2023	12,734
Thereafter	134,658
Total	$ 199,874

Goodwill

Goodwill amounting to $20.0 million and $21.0 million as of December 31, 2018 and 2017, respectively, represents the excess of the fair value of considerations transferred in business combination transactions over the fair value of tangible and intangible assets acquired, net of the fair value of liabilities assumed and non-controlling interest (as applicable) in the acquisitions.

During the fourth quarter of 2018, the Company determined that certain qualitative indicators of a potential impairment existed in relation to its storage and energy management services reporting unit which required further quantitative assessment of goodwill impairment (step one as described in Note 1 to the consolidated financial statements under the caption “Goodwill”). The qualitative indicators included a significant update to the reporting unit’s business forecasts combined with a large-scale restructuring of the way the Company runs this reporting unit which were both executed during the fourth quarter of 2018. As a result of the quantitative assessment, the Company recorded a goodwill impairment charge of $13.5 million in the consolidated statements of operations and comprehensive income (loss) for the year ended December 31, 2018. Following this impairment charge, the goodwill allocated to the storage and energy management services reporting unit is zero. The Company estimated the fair value of the storage and energy management services reporting unit by using the income approach based on discounted cash flows, which utilized Level 3 measurement that represent unobservable inputs into the Company’s valuation method.

Except as noted above, for the years 2018 and 2017, our impairment assessment related to the Company’s other reporting units for which goodwill is allocated to resulted in no impairment to goodwill.

Changes in the carrying amount of the Company’s goodwill for the years ended December 31, 2018 and 2017 were as follows:

	2018	**2017**
	(Dollars in thousands)	
Goodwill as of January 1,	$21,037	$6,650
Goodwill acquired	12,710	13,464
Goodwill impairment charge	(13,464)	-
Translation differences	(333)	923
Goodwill as of December 31,	$19,950	$21,037

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 10 — ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses consist of the following:

	December 31,	
	2018	**2017**
	(Dollars in thousands)	
Trade payable	$56,299	$64,289
Salaries and other payroll costs	20,188	19,888
Customer advances	918	1,177
Accrued interest	5,914	4,462
Income tax payable	8,436	43,682
Property tax payable	2,999	1,860
Scheduling and transmission	595	531
Royalty accrual	4,610	2,909
Deferred revenues	2,300	858
Warranty accrual	4,552	3,619
Other	9,551	10,521
Total	$116,362	$153,796

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 11 — LONG-TERM DEBT AND CREDIT AGREEMENTS

Long-term debt consists of notes payable under the following agreements:

	December 31, 2018	2017
	(Dollars in thousands)	
Limited and non-recourse agreements:		
Loans:		
Non-recourse:		
Other loans	$6,241	$7,252
Limited recourse:		
Loan agreement with OPIC (the Olkaria III power plant)	210,641	228,635
Loan agreement with OPIC (the Platanares power plant)	112,652	-
Loan agreement with Banco Industrial S.A. and Westrust Bank (International) Limited	29,750	33,251
Senior Secured Notes:		
Non-recourse:		
OrCal Senior Secured Notes	18,652	32,142
DAC 1 Senior Secured Notes	83,319	88,339
Limited recourse:		
OFC 2 Senior Secured Notes	217,810	232,526
Other loans	96,482	-
	775,547	622,145
Less current portion	(63,180)	(54,720)
Non current portion	$712,367	$567,425
Full recourse agreements:		
Senior Unsecured Bonds	$204,332	$204,332
Senior Unsecured Loan (Migdal)	100,000	-
Loan agreements with DEG (the Olkaria III and IV power plants)	47,500	50,000
Loan from a commercial bank	-	587
Revolving credit lines with banks	159,000	51,500
	510,832	306,419
Less current portion	(164,000)	(54,587)
Non current portion	$346,832	$251,832

Loan Agreement with Banco Industrial S.A. and Westrust Bank (International) Limited

On July 31, 2015, Ortitl n, Limitada, the Company's wholly owned subsidiary, 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 of 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 on 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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2018, the actual historical and projected 12-month Debt Service Coverage Ratio was 1.58 and 1.59, 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 collateralized 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. The Company’s obligations under the guaranty may be terminated prior to payment in full of the guaranteed obligations under certain circumstances described in the guaranty. If the guaranty is terminated early, the interest rate payable on the loan would increase as described above.

As of December 31, 2018, $29.8 million of this loan is outstanding.

Finance Agreement with OPIC (the Olkaria III Complex)

On August 23, 2012, OrPower 4, the Company's wholly owned subsidiary, 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 the Olkaria III geothermal power complex in Kenya. The Finance Agreement was amended on November 9, 2012.

The OPIC Loan is comprised of up to three tranches:

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

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

- Tranche III in an aggregate principal amount of $45.0 million was used to fund the construction of Plant 3 of the Olkaria III complex. In November 2013, an amount of $45.0 million was disbursed under this Tranche.

In July 2013, we completed the conversion of the interest rate applicable to both Tranche I and Tranche II from a floating interest rate to a fixed interest rate. The average fixed interest rate for Tranche I, which has an outstanding balance as of December 31, 2018 of $56.6 million and matures on December 15, 2030, and Tranche II, which has an outstanding balance as of December 31, 2018 of $121.8 million and matures on June 15, 2030, is 6.31%. In November 2013, we fixed the interest rate for Tranche III. The fixed interest rate for Tranche III, which has an outstanding balance as of December 31, 2018 of $32.2 million and matures on December 15, 2030, is 6.12%.

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

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The OPIC Loan is collateralized 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, 2018, the actual historical and projected 12-month DSCR was 2.87 and 3.03, respectively.

As of December 31, 2018, $210.6 million of the OPIC Loan was outstanding.

Debt service reserve

As required under the terms of the OPIC Loan, OrPower 4 maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OPIC Loan in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2018 and 2017, the balance of the account was $2.6 million and $3.7 million, respectively. In addition, as of December 31, 2018, part of the required debt service reserve was backed by a letter of credit in the amount of $16.1 million (see Note 22).

Well drilling reserve

As required under the terms of the OPIC Loan, OrPower 4 may be required to maintain an account which may be funded by cash or backed by letters of credit to reserve funds for future well drilling, based on determination upon the completion of the expansion work.

Finance Agreement with OPIC (the Platanares power plant)

On April 30, 2018, Geotérmica Platanares, S.A. de C.V. (“Platanares”), a Honduran sociedad anónima de capital variable and an indirect subsidiary of Ormat Technologies, Inc., entered into a Finance Agreement (the “Finance Agreement”) with OPIC, pursuant to which OPIC will provide to Platanares senior secured non-recourse debt financing in an aggregate principal amount of up to $124.7 million (the “Platanares Loan”), the proceeds of which will be used principally for the refinancing and financing of the Platanares 35 MW geothermal power plant located in western Honduras (the “Project”). The finance agreement was amended and closed in October of 2018.

Tranche I in an aggregate principal amount of $114.7 million was drawn in October 2018, carries a fixed interest rate of 7.02% per annum and matures in September of 2032. The closing of tranche II of up to $10 million is expected during the first half of 2019 subject to the satisfaction or waiver of certain conditions precedent.

Under the Finance Agreement, Platanares may, upon prior written notice to OPIC, make voluntary prepayments of the OPIC Loan, in whole or in part, in a minimum partial prepayment amount of $5 million together with payment to OPIC of all accrued but unpaid interest on the principal amount of the OPIC Loan to be prepaid, plus a prepayment premium. The prepayment premium is equal to (i) 2% of the principal amount of the OPIC Loan to be prepaid for any voluntary prepayment in the first or second year following expiration of the Commitment Period (as defined in the Finance Agreement) and (ii) 1% of the principal amount of the Platanares Loan to be prepaid for any voluntary prepayment in the third year following expiration of the Commitment Period. There is no prepayment premium for any voluntary prepayment in the fourth year following expiration of the Commitment Period or thereafter.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The OPIC Loan is also subject to customary mandatory prepayment upon the occurrence of certain events, including, among others, (i) receipt by Platanares of compensation or damages following a dispute that results in a material adverse change to the primary power purchase agreement for the Project, (ii) receipt by Platanares of a termination or indemnity payment from a third party (other than OPIC) or expropriation proceeds from a governmental authority upon the termination of any project documents or the condemnation, nationalization, seizure or expropriation of all or a substantial portion of the Project or property of Platanares by a governmental authority, respectively, and (iii) receipt by Platanares of sale proceeds in excess of a certain threshold from the disposition of all or any part of the property of Platanares, subject to certain exceptions.

The OPIC Loan will be secured by a first priority lien on all of the assets and ordinary shares of Platanares. The Finance Agreement contains various restrictive covenants applicable to Platanares, among others (i) to maintain a projected and historic debt service coverage ratio of no less than 1.1 to 1; (ii) to maintain on deposit in a debt service reserve account and well reserve account funds or assets with a value in excess of a minimum threshold and (iii) covenants that restrict Platanares from making certain payments or other distributions to its equity holders unless the projected and historic debt service coverage ratio is not less than 1.2 to 1. As of December 31, 2018, the projected 12-month Debt Service Coverage Ratio was 1.50.

The Finance Agreement also contains customary events of default, including, among others, failure to pay principal, interest or other amounts when due, non-payment or acceleration of other indebtedness of Platanares, the occurrence of a change of control of Platanares without the prior approval of OPIC, expropriation, judgments rendered against Platanares in excess of a certain threshold, failure to comply with covenants, a voluntary abandonment of the Project and the occurrence of certain bankruptcy events, subject to various exceptions and applicable notice, cure and grace periods.

As of December 31, 2018, $112.7 million of the Platanares OPIC Loan was outstanding.

Debt service reserve

As required under the terms of the Platanares Loan, Platanares maintains an account which may be funded by cash or backed by letters of credit in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the Platanares Loan in the following six months (or nine months in case of overdue payments by the offtaker up to a certain agreed threshold). This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2018, the balance of the account was $13.4 million and no letter of credit was required to be issued.

Well drilling reserve

As required under the terms of the Finance Agreement, Platanares is required to maintain an account which may be funded by cash or backed by letters of credit to reserve funds for well costs, based on certain determinations. As of December 31, 2018, the balance of the account was $2 million and no letter of credit was required to be issued.

OFC Senior Secured Notes

In February 2004, our subsidiary 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 financing the acquisition cost of 50% of the Mammoth complex. Principal and interest on the OFC Senior Secured Notes, which would have matured on December 30, 2020, were payable semi-annually. The OFC Senior Secured Notes were collateralized by substantially all of the assets of OFC and those of its wholly owned subsidiaries and 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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

OrCal Senior Secured Notes

In December 2005, OrCal, the Company's wholly owned subsidiary, issued $165.0 million, 6.21% Senior Secured Notes ("OrCal Senior Secured Notes") and received net cash proceeds of approximately $161.1 million, after deduction of issuance costs of approximately $3.9 million, which have been included in deferred financing costs in the consolidated balance sheet. The OrCal Senior Secured Notes have been rated BBB- by Fitch Ratings. The OrCal Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OrCal Senior Secured Notes are payable in semi-annual payments. The OrCal Senior Secured Notes are collateralized by substantially all of the assets of OrCal, and those of its 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 debt service coverage ratio ("DSCR") of not less than 1.25 (measured semi-annually as of June 30 and December 31 of each year). If OrCal fails to comply with the DSCR ratio it will be prohibited from making distributions to its shareholders. OrCal is only required to measure these covenants on a semi-annual basis and as of December 31, 2018, the last measurement date of the covenants, the actual historical 12-month DSCR was 1.18 and the pro-forma 12-month DSCR was 1.41. There was $18.7 million and $32.1 million of OrCal Senior Secured Notes outstanding as of December 31, 2018 and December 31, 2017, respectively.

OrCal may redeem the OrCal Senior Secured Notes, in whole or in part, at any time at a redemption price equal to the principal amount of the OrCal Senior Secured Notes to be redeemed plus accrued interest, and a "make-whole" premium. Upon certain events, as defined in the indenture governing the OrCal Senior Secured Notes, OrCal may be required to redeem a portion of the OrCal Senior Secured Notes at a redemption price of 100% of the principal amount of the OrCal Senior Secured Notes being redeemed plus accrued interest.

Debt service reserve

As required under the terms of the OrCal Senior Secured Notes, OrCal maintains an account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OrCal Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheets. As of December 31, 2018 and

2017, the balance of such account was $0.0 million and $1.9 million, respectively. In addition, as of each of December 31, 2018 and 2017, part of the required debt service reserve was backed by a letter of credit in the amount of $4.6 million (see Note 22).

OFC 2 Senior Secured Notes

In September 2011, OFC 2, the Company's wholly owned subsidiary and OFC 2's wholly owned project subsidiaries (collectively, the "OFC 2 Issuers") entered into a note purchase agreement (the "Note Purchase Agreement") with OFC 2 Noteholder Trust, as purchaser, John Hancock Life Insurance Company (U.S.A.), as administrative agent, and the DOE, as guarantor, in connection with the offer and sale of up to $350.0 million aggregate principal amount of OFC 2 Senior Secured Notes ("OFC 2 Senior Secured Notes") due December 31, 2034.

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

On October 31, 2011, the OFC 2 Issuers completed the sale of $151.7 million in aggregate principal amount of 4.687% Series A Notes due 2032 (the "Series A Notes"). The net proceeds from the sale of the Series A Notes, after deducting transaction fees and expenses, were approximately $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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On June 20, 2014, Phase 1 of Tuscarora Facility achieved Project Completion under the Note Purchase Agreement. In accordance with the terms of the Note Purchase Agreement and following recalibration of the financing assumptions, the loan amount was adjusted through a principal prepayment of $4.3 million.

On August 29, 2014, OFC 2 sold $140.0 million of OFC 2 Senior Secured Notes (the “Series C Notes”) to finance the construction of the second phase of the McGinness Hills project. The Series C Notes are the last tranche under the Note Purchase Agreement with John Hancock Life Insurance Company and are guaranteed by the DOE’s Loan Programs Office in accordance with and subject to the DOE's Loan Guarantee Program under Section 1705 of Title XVII of the Energy Policy Act of 2005. The Series C Notes, which mature in December 2032, carry a 4.61% coupon with principal to be repaid on a quarterly basis.

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

The Company concluded that the cash flow hedge was fully effective with no ineffective portion and no amounts excluded from the effectiveness testing, thus, in 2014, the total loss from the cash flow hedge was fully recognized in “Loss in respect of derivatives instruments designated for cash flow hedge” under other comprehensive income of $0.9 million noted above, which was net of related taxes of $0.6 million. The cash flow hedge loss recorded is amortized over the life of the OFC 2 Senior Secured Notes using the effective interest method. In 2016 and 2015, the Company reclassified $0.1 million, each year, of the loss from “Accumulated other comprehensive income (loss)” into interest expense.

The OFC 2 Senior Secured Notes are collateralized by substantially all of the assets of OFC 2 and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC 2. There are various restrictive covenants under the OFC 2 Senior Secured Notes, which include limitations on additional indebtedness of OFC 2 and its wholly owned subsidiaries. Failure to comply with these and other covenants will, subject to customary cure rights, constitute an event of default by OFC 2. In addition, there are restrictions on the ability of OFC 2 to make distributions to its shareholders.

Among other things, the distribution restrictions include a historical 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-months 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-months periods comprised of distinct consecutive fiscal quarters immediately following such proposed distribution. As of December 31, 2018, our historical DSCR was 2.55 and 2.21, respectively for each of the two six-month periods, and our projected future DSCR was 2.09 and 2.18, respectively for each of the two six-month periods.

There were $217.8 million and $232.5 million of OFC 2 Senior Secured Notes outstanding as of December 31, 2018 and December 31, 2017, respectively.

The Company provided a guaranty in connection with the issuance of the Series A Notes and Series C Notes. The guaranty may be drawn in the event of, among other things, the failure of any facility financed by the relevant series of OFC 2 Senior Secured Notes to reach completion and meet certain operational performance levels (the “non-performance trigger”) which gives rise to a prepayment obligation on the OFC 2 Senior Secured Notes. The guarantee may also be drawn if there is a payment default on the OFC 2 Senior Secured Notes or upon the occurrence of certain fundamental defaults that result in the acceleration of the OFC 2 Senior Secured Notes, in each case, prior to the date that the relevant facility(ies) financed by such OFC 2 Senior Secured Notes reaches completion and meets the applicable operational performance levels. The Company’s liability under the guaranty with respect to the non-performance trigger is limited to an amount equal to the prepayment amount on the OFC 2 Senior Secured Notes necessary to bring the OFC 2 Issuers into compliance with certain coverage ratios. The Company’s liability under the guarantee with respect to the other trigger event described above is not so limited.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Debt service reserve; other restricted funds

Under the terms of the OFC 2 Senior Secured Notes, OFC 2 is required to maintain a debt service reserve and certain other reserves, as follows:

(i) A debt service reserve account which may be funded by cash or backed by letters of credit (see below) in an amount sufficient to pay scheduled debt service amounts, including principal and interest, due under the terms of the OFC 2 Senior Secured Notes in the following six months. This restricted cash account is classified as current in the consolidated balance sheet. As of December 31, 2018, part of the required debt service reserve was backed by a letter of credit in the amount of $20.0 million (see Note 22).

(ii) A performance level reserve account, intended to provide additional security for the OFC 2 Senior Secured Notes, which may be funded by cash or backed by letters of credit. This reserve builds up over time and reduces gradually each time the project achieves certain milestones. Upon issuance of the Series A Notes, this reserve was funded in the amount of $28.0 million. As of December 31, 2018, the balance of such account was zero million, and no letter of credit was required to be issued.

(iii) Under the terms of the OFC 2 Senior Secured Notes, OFC 2 is also required to maintain a well field drilling and maintenance reserve that builds up over time and is dedicated to costs and expenses associated with drilling and maintenance of the project's well field, which may be funded by cash or backed by letters of credit.

(iv) A performance level reserve account for McGinness Hills Phase II, intended to provide additional security for the OFC 2 Senior Secured Notes, which may be funded by cash or backed by letters of credit. As of December 31, 2018, there was no requirement for an additional security to be issued as the project was completed.

Don A. Campbell Senior Secured Notes — Non-Recourse

On November 29, 2016, ORNI 47 LLC (“ORNI 47”), the Company’s subsidiary, 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 the first phase of the Don A. Campbell geothermal power plant (“DAC 1”), and part of the ORPD LLC (“ORPD”) portfolio.

The net proceeds 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 and ORNI 47 used the proceeds from the sale of the 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 March, June, September and December, until the DAC 1 Senior Secured Notes mature.

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 notes at 101% of the aggregate principal amount of such notes to be repurchased plus accrued and unpaid interest, if any, on such notes to, 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 of not less than 1.20 for the four fiscal quarterly periods. As of December 31, 2018, the historical and projected DSCR were 1.35 and 1.69, respectively.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2018, $83.3 million is outstanding under the DAC 1 Senior Secured Notes.

USG loans

On April 24, 2018, the Company completed the acquisition of USG. As part of the acquisition we assumed the following non-recourse loans:

Prudential Capital Group – Idaho non-recourse

In May 2016, USG's wholly owned subsidiary (Idaho USG Holdings LLC) entered into a loan agreement with the Prudential Capital Group to finance its development activities. The original principal totaled $20.0 million and included the option to issue additional debt up to $50.0 million within the following two years. The $20.0 million loan amount bears interest at a fixed interest rate of 5.8% per annum. The principal and interest payments are due semi-annually and the principal is partially repaid during the first seven-year term and the remaining balance of $16.0 million is due in full at this seven-year term. The loan is secured by the Company's ownership interests in the Neal Hot Springs project and the Raft River project projects. As of December 31, 2018, $18.9 million of the Prudential Capital loan is outstanding.

U.S. Department of Energy – non-recourse

On August 31, 2011, USG's wholly owned subsidiary, USG Oregon LLC ("USG Oregon"), completed the first funding drawdown associated with the U.S. Department of Energy ("DOE") $96.8 million loan guarantee ("Loan Guarantee") to construct its power plant at Neal Hot Springs project in Eastern Oregon. All loan advances covered by the Loan Guarantee have been made under the Future Advance Promissory Note dated February 23, 2011. In connection with the Loan Guarantee, the DOE has been granted a security interest in all of the equity interests of USG Oregon, as well as in the assets of USG Oregon, including a mortgage on real property interests relating to the Neal Hot Springs site. No additional advances are allowed under the terms of the loan. A total of 13 draws were taken and each individual draw or tranche is considered to be a separate loan. The loan principal is scheduled to be paid over 21.5 years from the first scheduled payment date with semi-annual installments including interest calculated at an aggregate fixed interest rate of 2.6%. The principal payment amounts are calculated on a straight-line basis according to the life of the loans and the original loan principal amounts. As of December 31, 2018, $51.4 million of the DOE loan is outstanding.

Prudential Capital Group – Nevada non-recourse

On September 26, 2013, USG's wholly owned subsidiary (USG Nevada LLC) entered into a note purchase agreement with the Prudential Capital Group to finance the Phase I of San Emidio geothermal project located in northwest Nevada. The term of the note is approximately 24 years and bears interest at a fixed rate of 6.75% per annum. Interest payments are due quarterly. Principal payments are due quarterly based upon minimum debt service coverage ratios established according to projected operating results made at the loan origination date and available cash balances. The loan agreement is secured by USG Nevada LLC's right, title and interest in and to its real and personal property, including the San Emidio project and the equity interests in USG Nevada LLC. As of December 31, 2018, $27.8 million of the loan is outstanding.

Senior Unsecured Bonds

In September 2016, the Company concluded an auction tender and accepted subscriptions for two series of senior unsecured bonds comprised of approximately $67 million aggregate principal amount of senior unsecured bonds (the "Series 2 Bonds") and approximately $137 million aggregate principal amount of senior unsecured bonds (the "Series 3 Bonds" and together with the Series 2 Bonds, the "Senior Unsecured Bonds"). The proceeds from the Series 2 Bonds and Series 3 Bonds were used on September 29, 2016 to prepay the Company's $250 million aggregate principal amount of previously issued bonds that were payable on August 1, 2017.

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 by the Company pursuant to the terms and conditions of the trust instrument that governs such Senior Unsecured Bonds.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Senior Unsecured Loan

On March 22, 2018 the Company entered into a definitive loan agreement (the "Migdal Loan Agreement") with Migdal Insurance Company Ltd., Migdal Makefet Pension and Provident Funds Ltd. and Yozma Pension Fund of Self-Employed Ltd., all entities within the Migdal Group, a leading insurance company and institutional investor in Israel. The Migdal Loan Agreement provides for a loan by the lenders to the Company in an aggregate principal amount of $100.0 million (the "Migdal Loan"). The Migdal Loan will be repaid in 15 semi-annual payments of $4.2 million each, commencing on September 15, 2021, with a final payment of $37.0 million on March 15, 2029. The Migdal Loan bears interest at a fixed rate of 4.8% per annum, payable semi-annually, subject to adjustment in certain circumstances as described below.

The Loan is subject to early redemption by the Company prior to maturity from time to time (but not more frequently than once per quarter) and at any time in whole or in part, at a redemption price set forth in the Migdal Loan Agreement. If the rating of the Company is downgraded to "ilA-"(or equivalent), of any of Standard and Poor’s, Moody’s or Fitch (whenever in Israel or outside of Israel) (each a “Credit Rating Agency”), the interest rate applicable to the Migdal Loan will increase by 0.50%. If the rating of the Company is further downgraded to a lower level by any Credit Rating Agency, the interest rate applicable to the Migdal Loan will be increased by 0.25% for each additional downgrade. In no event will the cumulative increase in the interest rate applicable to the Loan exceed 1% regardless of the cumulative rating downgrade. A subsequent upgrade or reinstatement of a rating by any Credit Rating Agency will reduce the interest rate applicable to the Migdal Loan by 0.25% for each upgrade (but in no event will the interest rate applicable the Migdal Loan fall below the base interest rate of 4.8%). Additionally, if the ratio between short-term and long-term debt to financial institutions and bondholders, deducting cash and cash equivalents to EBITDA is equal to or higher than 4.5, the interest rate on all amounts then outstanding under the Migdal Loan shall be increased by 0.5% per annum over the interest rate then-applicable to the Migdal Loan.

The Migdal Loan constitutes senior unsecured indebtedness of the Company and will rank equally in right of payment with any existing and future senior unsecured indebtedness of the Company, and effectively junior to any existing and future secured indebtedness, to the extent of the security therefore.

The Migdal Loan Agreement includes various affirmative and negative covenants, including a covenant that the Company maintain (i) a debt to adjusted EBITDA ratio below 6, (ii) a minimum equity amount (as shown on its consolidated financial statements, excluding noncontrolling interests) of not less than $650 million, and (iii) an equity attributable to Company's stockholders to total assets ratio of not less than 25%. In addition, the Migdal Loan Agreement restricts the Company from making dividend payments if its equity falls below $800 million and otherwise restricts dividend payments in any one year to not more than 50% of the net income of the Company of such year as shown on the Company’s consolidated annual financial statements as long as any of the Company's bonds issued in Israel prior to March 27, 2018 remain outstanding. The Migdal Loan Agreement includes other customary affirmative and negative covenants and events of default.

Loan Agreements with DEG (the Olkaria III Complex)

In March 2009, OrPower 4, the Company’s wholly owned subsidiary, entered into a project financing loan of $105.0 million to refinance its investment in Phase I of the Olkaria III complex located in Kenya (the “DEG Loan”). The DEG Loan was provided by a group of European DFIs arranged by DEG. The DEG Loan was to mature on December 15, 2018, and payable in 19 equal semi-annual installments. Interest on the loan was variable based on 6-month LIBOR plus 4.0%. The Company fixed the interest rate on most of the loan at 6.90%. In September 2017, the Company 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 amount of $50 million, with a fixed interest rate of 6.28% for the duration of the loan (the “DEG 2 Loan”). The DEG 2 Loan will be repaid in 20 equal semi-annual principal installments commencing December 21, 2018, with a final maturity date of June 21, 2028. 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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2018, $47.5 million is outstanding under the DEG 2 Loan.

Revolving credit lines with commercial banks

As of December 31, 2018, the Company has credit agreements with eight commercial banks for an aggregate amount of $468.0 million (including $60.0 million from Union Bank, N.A. ("Union Bank") and $35.0 million from HSBC), as described below. Under the terms of these credit agreements, the Company, or its Israeli subsidiary, Ormat Systems Ltd. ("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 $235.0 million. The credit agreements mature between end of March 2019 and September 2019. 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, 2018, $159.0 million in loans were outstanding, of which $14.1 million are non-committed, and letters of credit with an aggregate stated amount of $229.6 million were issued and outstanding under such credit agreements.

Credit Agreements

Credit agreement with Union Bank

In February 2012, Ormat Nevada Inc. (“Ormat Nevada”), the Company’s 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, 2019. On December 31, 2018, the aggregate amount available under the credit agreement was $60 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, the Company entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which the Company 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, which include 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, 2018: (i) the actual 12-month debt to EBITDA ratio was 2.91; (ii) the 12-month DSCR was 2.94; and (iii) the distribution leverage ratio was 1.10. 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, 2018, letters of credit in the aggregate amount of $51.5 million remain issued and outstanding under this credit agreement with Union Bank.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Credit agreement with 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 facility under this credit agreement is August 31, 2019. The aggregate amount available under the credit agreement was increased by $10 million to $35 million. Other than the $10 million of this credit facility which may be drawn for our working capital needs, this credit line 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 parties thereto. In connection with this transaction, we entered into a guarantee in favor of the administrative agent for the benefit of the banks, pursuant to which we agreed to guarantee Ormat Nevada's obligations under the credit agreement. Ormat Nevada's obligations under the credit agreement are otherwise unsecured.

There are various restrictive covenants under the credit agreement, including a requirement to comply with the following financial ratios, which are measured quarterly: (i) a 12-month debt to EBITDA ratio not to exceed 4.5; (ii) 12-month DSCR of not less than 1.35; and (iii) distribution leverage ratio not to exceed 2.0. As of December 31, 2018: (i) the actual 12-month debt to EBITDA ratio was 2.91; (ii) the 12-month DSCR was 2.94; and (iii) the distribution leverage ratio was 1.10. 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, 2018, letters of credit in the aggregate amount of $30.0 million remain issued and outstanding under this 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, 2018, Chubb issued a surety bond in the amount of $141.1 million under the Surety Agreement.

Restrictive covenants

The Company's obligations under the credit agreements, the loan agreements, and the trust instrument governing the bonds, described above, are unsecured, but 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, as well as the trust instrument contain cross-default provisions with respect to other material indebtedness owed by us to any third party. In some cases, the Company has agreed to maintain certain financial ratios, which are measured quarterly, such as: (i) equity of at least $600.0 million and in no event less than 25% of total assets; (ii) 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio not to exceed 6; and (iii) dividend distribution not to exceed 35% of net income for that year. As of December 31, 2018: (i) total equity was $1,445.1 million and the actual equity to total assets ratio was 46.3%, and (ii) the 12-month debt, net of cash, cash equivalents marketable securities and short-term bank deposits to Adjusted EBITDA ratio was 3.21. During the year ended December 31, 2018, the Company distributed interim dividends in an aggregate amount of $26.8 million.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Future minimum payments

Future minimum payments under long-term obligations, excluding revolving credit lines with commercial banks, as of December 31, 2018 are as follows:

	(Dollars in thousands)
Year ending December 31:	
2019	$68,180
2020	136,018
2021	64,039
2022	205,908
2023	84,101
Thereafter	570,751
Total	$1,128,997

NOTE 12 — PUNA POWER PLANT LEASE TRANSACTIONS

In 2005, the Company's wholly owned subsidiary in Hawaii, Puna Geothermal Ventures ("PGV"), entered into transactions 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 company in return for prepaid lease payments in the total amount of $83.0 million (the "Deferred Lease Income"). The carrying value of the leased assets as of December 31, 2018 and 2017 amounted to $19.7 million and $25.3 million, net of accumulated depreciation of $33.1 million and $35.6 million, respectively. The unrelated company (the "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 Lessor as part of the Head Lease but are part of the Lessor's security package.

The Head Lease and the Project Lease are being accounted for separately. Each was classified as an operating lease in accordance with the accounting standards for leases. The Deferred Lease Income is amortized into revenue, using the straight-line method, over the 31-year term of the Head Lease. Deferred transaction costs amounting to $4.2 million are being amortized, using the straight-line method, over the 23-year term of the Project Lease.

Future minimum lease payments under the Project Lease, as of December 31, 2018, are as follows:

	(Dollars in thousands)
Year ending December 31:	
2019	$ 6,018
2020	2,450
2021	1,723
2022	824
2023	-
Thereafter	1,917
Total	$ 12,932

Depository accounts

As required under the terms of the lease agreements, there are certain reserve funds that need to be managed by the indenture trustee in accordance with certain balance requirements. Such reserve funds amounted to $1.3 million and $7.9 million as of December 31, 2018 and 2017, 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.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Distribution account

PGV maintains an account to deposit its remaining cash, after making all of the necessary payments and transfers as provided for in the lease agreements, in order to make distributions to Ormat Nevada. The distributions are allowed only if PGV maintains various restrictive covenants under the lease agreements, which include limitations on additional indebtedness. As of December 31, 2018 and 2017, the balance of such account was $0.

NOTE 13 —TAX MONETIZATION TRANSACTIONS

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 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 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 second phase 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. The Company expects 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 production tax credits 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 LLC 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 LLC, will effectively retain the day-to-day control and management of Opal Geo and its portfolio of five power plants.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 approximately $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 liability associated with sale of tax benefits as described in Note 1. 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.

Tungsten Mountain partnership transaction

On May 17, 2018, one of the Company's wholly-owned subsidiaries that indirectly owns the 26 MW Tungsten Mountain Geothermal power plant entered into a partnership agreement with a private investor. Under the transaction documents, the private investor acquired membership interests in the Tungsten Mountain Geothermal power plant project for an initial purchase price of approximately $33.4 million and for which it will pay additional installments that are expected to amount to approximately $13 million. The Company will continue to operate and maintain the power plant and will receive substantially all the distributable cash flow generated by the power plant.

Under the agreements, prior to December 31, 2026 (“Target Flip Date”), the Company’s fully owned subsidiary, Ormat Nevada Inc. ("Ormat Nevada"), receives substantially all of the distributable cash flow generated by the project, while the private investor receives substantially all of the tax attributes of the project. Following the later of the Target Flip Date and the date in which the private investor reaches its target return, Ormat Nevada will receive 97.5% of the distributable cash and 95.0% of the taxable income, on a going forward basis.

On the Target Flip Date, Ormat Nevada has the option to purchase the private investor’s interests at the then-current fair market value, plus an amount that may be needed to cause the private investor to reach its target return, if needed. If Ormat Nevada exercises this purchase option, it will become the sole owner of the project again.

Other completed tax monetization transactions

On May 31, 2017, the Company’s partners JPM and Morgan Stanley achieved their target after-tax yield on its investment in OPC and on October 31, 2017, Ormat Nevada purchased all of the Class B membership units in OPC from JPM and Morgan Stanley for $1.9 million. As a result, Ormat Nevada is now the sole owner of all of the economic and voting interests in OPC and continues to consolidate OPC in its financial statements. The purchase of Class B membership units of OPC was recorded in equity as a reduction of $6.5 million to Noncontrolling Interest with the surplus of $8.5 million charged to Additional Paid-in Capital.

In March 2017, JPM achieved its target after-tax yield on its investment in ORTP and on July 10, 2017, Ormat Nevada purchased all of the Class B membership units in ORTP from JPM for $2.4 million. As a result, Ormat Nevada is now the sole owner of all of the economic and voting interests in ORTP and continues to consolidate ORTP in its financial statements. The purchase of Class B membership units of ORTP was recorded in equity as a reduction to Noncontrolling Interest of $7.0 million with the surplus of $ $2.9 million charged to Additional Paid-in Capital.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 14 — ASSET RETIREMENT OBLIGATION

The following table presents a reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligation for the years presented below:

	Year Ended December 31,	
	2018	**2017**
	(Dollars in thousands)	
Balance at beginning of year	$27,110	$23,348
Revision in estimated cash flows	(258)	1,888
Liabilities incurred and acquired	10,149	—
Accretion expense	2,474	1,874
Balance at end of year	$39,475	$27,110

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 15 — STOCK-BASED COMPENSATION

The Company makes an estimate of expected forfeitures and recognizes compensation costs only for those stock-based awards expected to vest. As of December 31, 2018, the total future compensation cost related to unvested stock-based awards that are expected to vest is $17.0 million, which will be recognized over a weighted average period of 1.3 years.

During the years ended December 31, 2018, 2017 and 2016, the Company recorded compensation related to stock-based awards as follows:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(Dollars in thousands, except per share data)		
Cost of revenues	$3,488	$3,369	$2,400
Selling and marketing expenses	792	452	247
General and administrative expenses	5,938	4,939	2,510
Total stock-based compensation expense	10,218	8,760	5,157
Tax effect on stock-based compensation expense	668	604	617
Net effect of stock-based compensation expense	$9,550	$8,156	$4,540

During the fourth quarters of 2018, 2017 and 2016, the Company evaluated the trends in the stock-based award forfeiture rate and determined that the actual rates are 5.3%, 1.1% and 10.3%, respectively. This represents an increase of 381.8%, a decrease of 89.3%, and an increase of 7%, respectively, from prior estimates. As a result of the change in the estimated forfeiture rate, there was an immaterial impact on stock-based compensation expense for each of the respective periods.

Valuation assumptions

Prior to 2016, the fair value of each grant of stock-based awards was estimated using the Black-Scholes valuation model. The Company's expected term represented the period that the Company's stock-based awards were expected to be outstanding. In the absence of enough historical information, the expected term was determined using the simplified method giving consideration to the contractual term and vesting schedule. Starting in 2016, the Company estimated the fair value of the stock-based awards using the Exercise Multiple-Based Lattice Model as it enables a degree of accounting for the complexities of option valuation and reduces the probability of a measurement error. The dividend yield forecast is expected to be 20% of the Company's yearly net profit, which is equivalent to a 0.9% yearly weighted average dividend rate in the year ended December 31, 2018. The risk-free interest rate was based on the yield from U.S. constant treasury maturities bonds with an equivalent term. The forfeiture rate is based on trends in actual stock-based awards forfeitures.

The Company calculated the fair value of each stock-based award on the date of grant based on the following assumptions:

	Year Ended December 31,		
	2018	**2017**	**2016**
For stock options issued by the Company:			
Risk-free interest rates	2.8 %	1.9 %	1.3 %
Expected lives (in weighted average years)	3.5	3.1	4.5
Dividend yield	0.90%	0.62%	1.10%
Expected volatility (weighted average)	25.5%	27.2%	30.7%
Forfeiture rate (weighted average)	3.1 %	0.0 %	8.4 %

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Stock-based awards

The 2012 Incentive Compensation Plan

In May 2012, the Company's shareholders adopted the 2012 Incentive Plan, which provides for the grant of the following types of awards: incentive stock options, non-qualified stock options, restricted stock, stock appreciation rights "(SARs"), stock units, performance awards, phantom stock, incentive bonuses, and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2012 Incentive Plan, a total of 4,000,000 shares of the Company's common stock were reserved for issuance, all of which could be issued as options or as other forms of awards. Options and SARs granted to employees under the 2012 Incentive Plan typically vest and become exercisable as follows: 25% vest 24 months after the grant date, an additional 25% vest 36 months after the grant date, and the remaining 50% vest 48 months after the grant date. Options granted to non-employee directors under the 2012 Incentive Plan will vest and become exercisable one year after the grant date. Restricted stock units granted to directors and members of senior management vest according to a vesting schedule as follows: for the directors, 100% on the first anniversary of the grant date and for members of senior management, 25% on each of the first, second, third and fourth anniversaries of the grant date. The term of stock-based awards typically ranges from six to ten years from the grant date. The shares of common stock issued in respect of awards under the 2012 Incentive Plan are issued from the Company's authorized share capital upon exercise of options or SARs. The 2012 Incentive Plan expired in May 2018 upon adoption of the 2018 Incentive Compensation Plan ("2018 Incentive Plan"), except as to stock-based awards outstanding under the 2012 Incentive Plan on that date.

The 2018 Incentive Compensation Plan

On May 7, 2018, the Company held its 2018 Annual Meeting of Stockholders at which the Company's stockholders approved the 2018 Incentive Plan. The 2018 Incentive Plan provides for the grant of the following types of awards: incentive stock options, restricted stock units ("RSUs"), SARs, stock units, performance awards, phantom stock, incentive bonuses and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2018 Incentive Plan, a total of 5,000,000 shares of the Company's common stock were authorized and reserved for issuance, all of which could be issued as options or as other forms of awards. SARs and RSUs granted to employees under the 2018 Incentive Plan typically vest and become exercisable as follows: 50% on the second anniversary of the grant date and 25% on each of the third and fourth anniversaries of the grant date. SARs and Restricted stock units granted to directors under the 2018 Incentive Plan typically vest and become exercisable (100%) on the first anniversary of the grant date. The term of stock-based awards typically ranges from six to ten years from the grant date. The shares of common stock issued in respect of awards under the 2018 Incentive Plan are issued from the Company's authorized share capital upon exercise of options or SARs.

On June 13, 2016, the Company granted its employees, an aggregate of 1,080,000 SARs under the Company's 2012 Incentive Plan. The exercise price of each SAR is $42.87, which represented the fair market value of the Company's common stock on the grant date. Such SARs will expire six years from the date of the grant and will vest over 4 years as follows: 50% after two years; an additional 25% after three years and the remaining 25% after four years from the grant date.

The fair value of each SAR on the grant date was $11.98 for senior management and $11.42 for other employees. The Company calculated the fair value of each SAR on the grant date using the Exercise Multiple-Based Lattice SAR-Pricing model based on the following assumptions:

Risk-free interest rate	1.29%
Expected life (in years)	6
Dividend yield	1.14%
Expected volatility	30.7%
Forfeiture rate:	
Senior management	0.0 %
Other employees	10.5%
Sub-Optimal Exercise Factor:	
Senior management	2.5
Other employees	2.0

On November 8, 2016, the Company granted its directors, an aggregate of 60,000 SARs under the Company's 2012 Incentive Plan. The exercise price of each SAR is $47.46, which represented the fair market value of the Company's common stock on the grant date. Such SARs will expire seven years from the date of the grant and will vest at the end of the first year from the grant date.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of each SAR on the grant date was $14.51. The Company calculated the fair value of each SAR on the grant date using the Exercise Multiple-Based Lattice SAR-Pricing model based on the following assumptions:

Risk-free interest rate	1.65 %
Expected life (in years)	7
Dividend yield	1.1 %
Expected volatility	30.6 %
Forfeiture rate	0.0 %
Sub-Optimal Exercise Factor	2.5

On June 7, 2017, the Company granted its employees, an aggregate of 23,200 SAR's under the Company's 2012 Incentive Plan. The exercise price of each SAR is $58.79, which represented the fair market value of the Company's common stock on the grant date. Such SARs will expire five years from the date of the grant. Such SARs will vest according to a vesting schedule as follows: 50% on the first anniversary of the grant date and 25% on each of the third and fourth anniversaries of the grant date.

The fair value of each SAR on the grant date was $13.67. The Company calculated the fair value of each SAR on the grant date using the Exercise Multiple-Based Lattice SAR-Pricing model based on the following assumptions:

Risk-free interest rate	1.74 %
Expected life (in years)	5
Dividend yield	0.66 %
Expected volatility	26.3 %
Forfeiture rate	10.3 %
Sub-Optimal Exercise Factor	2

On August 4, 2017, the Company granted its directors, an aggregate of 30,000 options under the Company's 2012 Incentive Plan. The exercise price of each option is $57.97, which represented the fair market value of the Company's common stock on the grant date. Such options will expire seven years from the date of the grant and will fully vest one year from the grant date.

The fair value of each option on the grant date was $18.42. The Company calculated the fair value of each option on the grant date using the Exercise Multiple-Based Lattice SAR-Pricing model based on the following assumptions:

Risk-free interest rate	2.08 %
Expected life (in years)	7
Dividend yield	0.69 %
Expected volatility	29.4 %
Forfeiture rate	0.0 %
Sub-Optimal Exercise Factor	2.5

On November 8, 2017, the Company granted its directors and members of its senior management an aggregate of 108,771 SARs and 22,742 Restricted Stock Units ("RSUs") under the Company's 2012 Incentive Plan. The exercise price of each SAR is $63.35, which represented the fair market value of the Company's common stock on the grant date. Such SARs and RSUs will expire in six years and will vest according to a vesting schedule as follows: for the directors, 100% on the first anniversary of the grant date and for members of senior management, 25% on each of the first, second, third and fourth anniversaries of the grant date.

The fair value of each SAR for the directors and members of senior management on the grant date was $17.6 and $17.7, respectively. The fair value of each RSU for the directors and members of senior management on the grant date was $62.9 and $62.3, respectively. The Company calculated the fair value of each SAR and RSU on the grant date using the Exercise Multiple-Based Lattice Pricing model based on the following assumptions:

Risk-free interest rate	2.1 %
Expected life (in years)	6
Dividend yield	0.6 %
Expected volatility	26.9 %
Forfeiture rate	0.0 %
Sub-Optimal Exercise Factor	2.5

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On May 8, 2018, the Company granted an aggregate of 295,671 SARs and 40,489 RSUs to the CEO and one of the directors under the Company's 2018 Incentive Plan. The exercise price of each SAR is $55.16, which represented the fair market value of the Company's common stock on the grant date. The SARs and RSUs will expire in five and a half years from the date of grant and will vest according to a vesting schedule as follows: for the director, 100% after a half year from the grant date and for the CEO, 22% on the half year and one and a half year from the grant date and 28% on the two and a half and three and a half year from the grant date.

The fair value of each SAR for the director and the CEO on the grant date was $14.56 and $14.57, respectively. The fair value of each RSU for the director and the CEO on the grant date was $54.92 and $54.23, respectively. The Company calculated the fair value of each SAR and RSU on the grant date using the Exercise Multiple-Based Lattice Pricing model based on the following assumptions:

Risk-free interest rate	2.84	%
Expected life (in years)	1.9 – 3.5	
Dividend yield	0.79	%
Expected volatility	25.24	%
Forfeiture rate	0.0	%
Sub-Optimal Exercise Factor	2.5	

On June 25, 2018, the Company granted its employees and members of its senior management an aggregate of 841,117 SARs and 19,848 RSUs under the Company's 2018 Incentive Plan. The exercise price of each SAR is $53.44, which represented the fair market value of the Company's common stock on the grant date. The SARs and RSUs will expire in six years from the date of grant and will vest according to a vesting schedule as follows: 50% on the second anniversary of the grant date and 25% on each of the third and fourth anniversaries of the grant date.

The fair value of each SAR for the employees and members of senior management on the grant date was $13.82 and $14.64, respectively. The fair value of each RSU for the members of senior management on the grant date was $52.09, respectively. The Company calculated the fair value of each SAR and RSU on the grant date using the Exercise Multiple-Based Lattice Pricing model based on the following assumptions:

Risk-free interest rate	2.79 %
Expected life (in years)	3.5 – 3.7
Dividend yield	0.92 %
Expected volatility	25.64 %
Forfeiture rate for employees	2.78 %
Forfeiture rate for members of the senior management	0.0 %
Sub-Optimal Exercise Factor for employees	2.0
Sub-Optimal Exercise Factor for members of the senior management	2.8

On November 7, 2018, the Company granted its directors and employees an aggregate of 35,395 SARs and 13,688 Restricted Stock Units ("RSUs") under the Company's 2018 Incentive Plan. The exercise price of each SAR was $53.16 which represented the fair market value of the Company's common stock on the grant date. Such SARs and RSUs will expire in six years and will vest according to a vesting schedule as follows: for the directors, 100% on the first anniversary of the grant date and for the employees, 50% on the second anniversary of the grant date and 25% on each of the third and fourth anniversaries of the grant date.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of each SAR for the directors and employees on the grant date was $14.8 and $14.0, respectively. The fair value of each RSU for the directors on the grant date was $52.6. The Company calculated the fair value of each SAR and RSU on the grant date using the Exercise Multiple-Based Lattice Pricing model based on the following assumptions:

Risk-free interest rate	3.11	%
Expected life (in years)	2.0 – 3.6	
Dividend yield	1.03	%
Expected volatility	25.87	%
Forfeiture rate for directors	0.0	%
Forfeiture rate for employees	2.78	%
Sub-Optimal Exercise Factor for directors	2.8	
Sub-Optimal Exercise Factor for employees	2.0	

	Year Ended December 31,					
	2018		**2017**		**2016**	
	Shares (In thousands)	**Weighted Average Exercise Price**	**Shares (In thousands)**	**Weighted Average Exercise Price**	**Shares (In thousands)**	**Weighted Average Exercise Price**
Outstanding at beginning of year	1,548	$ 41.35	2,565	$ 33.36	2,438	$ 25.38
Granted, at fair value:						
Stock Options	—	—	30	57.97	1,155	43.01
SARs*	1,172	53.87	132	62.55	—	—
RSUs**	74	—	23	—	—	—
Exercised	(203)	29.75	(1,181)	25.92	(967)	25.33
Forfeited	(64)	45.73	(21)	46.15	(57)	24.12
Expired	—	—	—	—	(4)	26.84
Outstanding at end of year	2,527	46.77	1,548	41.35	2,565	33.36
Options and SARs exercisable at end of year	846	42.06	431	32.61	557	25.22
Weighted-average fair value of options and SARs granted during the year		$ 16.45		$ 22.82		$ 11.61

* Upon exercise, SARs entitle the recipient to receive shares of common stock equal to the increase in value of the award between the grant date and the exercise date.

** An RSU represents the right to receive one share of common stock once certain vesting conditions are met. The value of an RSU is identical to the value of the underlying stock.

As of December 31, 2018, 3,605,740 shares of the Company’s common stock are available for future grants under the 2018 Incentive Plan. No shares of the Company’s common stock are available for future grants under the 2012 and 2004 Incentive Plan as of such date.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes information about stock-based awards outstanding at December 31, 2018 (shares in thousands):

Exercise Price	Options Outstanding: Number of Stock-based Awards Outstanding	Options Outstanding: Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value	Options Exercisable: Number of Stock-based Awards Exercisable	Options Exercisable: Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value
$ -	75	1.8	3,933	-	-	-
20.13	29	0.3	924	29	0.3	924
23.34	99	0.4	2,897	99	0.4	2,897
35.15	15	4.1	257	15	4.1	257
38.24	15	3.8	211	15	3.8	211
42.87	942	3.5	8,879	521	3.5	4,918
47.46	38	4.9	182	38	4.9	182
53.16	35	5.9	-	-	-	-
53.44	828	5.5	-	-	-	-
55.16	296	4.9	-	66	4.9	-
57.97	30	5.6	-	30	5.6	-
58.79	16	3.5	-	-	-	-
63.35	109	4.9	-	33	4.9	-
	2,527	4.3	$ 17,283	846	3.3	$ 9,389

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes information about stock-based awards outstanding at December 31, 2017 (shares in thousands):

	Options Outstanding			Options Exercisable		
Exercise Price	Number of Stock-based Awards Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value	Number of Stock-Based Awards Exercisable	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value
$ -	23	3.9	1,455	-	-	-
20.13	35	1.3	1,533	35	1.3	1,533
23.34	176	1.4	7,150	176	1.4	7,150
25.65	10	0.3	398	10	0.3	398
35.15	15	5.1	432	15	5.1	432
38.24	15	4.8	386	15	4.8	386
42.87	1,074	4.5	22,651	143	4.5	3,005
47.46	38	5.9	619	38	5.9	619
57.97	30	6.6	180	-	-	-
58.79	23	4.5	120	-	-	-
63.35	109	5.9	66	-	-	-
	1,548	4.2	$ 34,990	432	3.0	$ 13,523

The aggregate intrinsic value in the above tables represents the total pretax intrinsic value, based on the Company’s stock price of $52.30 and $63.96 as of December 31, 2018 and 2017, respectively, which would have potentially been received by the stock-based award holders had all stock-based award holders exercised their stock-based award as of those dates. The total number of in-the-money stock-based awards exercisable as of December 31, 2018 and 2017 was 846,215 and 431,387, respectively.

The total pretax intrinsic value of options exercised during the year ended December 31, 2018 and 2017 was $5.2 million and $38.9 million, respectively, based on the average stock price of $55.58 and $58.82 during the years ended December 31, 2018 and 2017, respectively.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 16 — POWER PURCHASE AGREEMENTS

Substantially all of the Company's electricity revenues are recognized pursuant to PPAs in the U.S. and in various foreign countries, including Kenya, Guatemala, Guadeloupe and Honduras. These PPAs generally provide for the payment of energy payments or both energy and capacity payments through their respective terms which expire in varying periods from 2019 to 2043. Generally, capacity payments are calculated based on the amount of time that the power plants are available to generate electricity. The energy payments are calculated based on the amount of electrical energy delivered at a designated delivery point. The price terms are customary in the industry and include, among others, a fixed price, SRAC (the incremental cost that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others), and a fixed price with an escalation clause that includes the value for environmental attributes, known as renewable energy credits. Certain of the PPAs provide for bonus payments in the event that the Company is able to exceed certain target levels and potential payments by the Company if it fails to meet minimum target levels. One PPA gives the power purchaser or its designee the right of first refusal to acquire the geothermal power plants at fair market value. Upon satisfaction of certain conditions specified in this PPA, and subject to receipt of requisite approvals and negotiations between the parties, the Company has the right to demand that the power purchaser acquire the power plant at fair market value. The Company's subsidiaries in Guatemala sell power at an agreed upon price subject to terms of a "take or pay" PPA.

Pursuant to the terms of certain of the PPAs, the Company 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 the Company does not meet certain minimum performance requirements, the capacity of the power plant may be permanently reduced.

As discussed in Note 1, the Company assessed all PPAs agreed to, modified or acquired in business combinations on or after July 1, 2003, and evaluated whether such PPAs contained a lease element requiring lease accounting. Future lease revenues under PPAs which contain a lease element as of December 31, 2018 including the PPAs that provide for minimum production or performance guarantees are accounted for as contingent lease revenues as they are production-based payments and contingent on generation levels that are impacted by climatic variables that are inherently uncertain including geological conditions and ambient temperature. The PPAs considered to be leases were also assessed for inclusion of embedded derivatives, which required that they be separately accounted for at fair value. However, none of such PPAs were determined to include embedded derivatives.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 17 — INTEREST EXPENSE, NET

The components of interest expense are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Interest related to sale of tax benefits	$11,284	$6,985	$9,349
Interest expense	63,368	54,381	61,327
Less — amount capitalized	(3,728)	(7,224)	(3,287)
	$70,924	$54,142	$67,389

NOTE 18 — INCOME TAXES

U.S. and foreign components of income from continuing operations, before income taxes and equity in income (losses) of investees consisted of:

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
U.S	$14,097	$13,680	$(7,109)
Non-U.S. (foreign)	123,084	157,050	148,197
Total income from continuing operations, before income taxes and equity in losses	$137,181	$170,730	$141,088

The components of the provision (benefit) for income taxes, net are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Current:			
Federal	$—	$43,935	$—
State	381	43	(276)
Foreign	14,992	11,186	13,554
Total current income tax expense	$15,373	$55,164	$13,278
Deferred:			
Federal	(6,886)	(55,718)	57
State	(2,595)	(3,284)	—
Foreign	28,841	25,502	23,724
Total deferred tax benefit	19,360	(33,500)	23,781
Total Income tax provision	$34,733	$21,664	$37,059

193

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Reconciliation of the U.S. federal statutory tax rate to the Company's effective income tax rate is as follows:

	Year Ended December 31,		
	2018	2017	2016
U.S. federal statutory tax rate	21.0 %	35.0 %	35.0 %
Impact of federal tax reform	2.6	(12.4)	-
Transition tax inclusion	(5.7)	42.1	-
Foreign tax credits	(4.2)	(50.5)	-
Tax basis adjustment	-	-	(4.9)
Withholding tax	5.9	34.1	-
Valuation allowance - U.S.	(17.2)	(22.6)	16.5
State income tax, net of federal benefit	1.0	1.1	(0.6)
Uncertain Tax Positions	2.1	-	-
Effect of foreign income tax, net	5.6	(10.7)	(10.3)
Production tax credits	(3.1)	(1.2)	(8.3)
Subpart F income	0.5	1.7	0.3
Tax on global intangible low-tax income	18.6	-	-
Intra-entity transfers of assets other than inventory	(2.1)	-	-
Other, net	0.3	(3.9)	(1.4)
Effective tax rate	25.3 %	12.7 %	26.3 %

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The net deferred tax assets and liabilities consist of the following:

	December 31, 2018	**2017**
	(Dollars in thousands)	
Deferred tax assets (liabilities):		
Net foreign deferred taxes, primarily depreciation	$(57,202)	$(61,961)
Depreciation	(30,500)	(65,315)
Intangible drilling costs	7,370	13,003
Net operating loss carryforward - U.S.	65,020	55,084
Tax monetization transaction	(17,104)	(13,134)
State and Investment tax credits	813	813
Production tax credits	90,913	85,193
Foreign tax credits	58,072	86,206
Withholding tax	(8,052)	(14,400)
Stock options amortization	1,440	1,166
Basis difference in partnership interest	(36,516)	(16,817)
Accrued liabilities and other	624	3,109
	74,878	72,947
Less - valuation allowance	(22,441)	(77,571)
Total	$52,437	$(4,624)

The following table presents a reconciliation of the beginning and ending valuation allowance:

	2018	**2017**	**2016**
	(Dollars in thousands)		
Balance at beginning of the year	$77,571	$116,234	$92,898
Additions to valuation allowance	4,747	46,560	23,336
Release of valuation allowance	(59,877)	(85,223)	-
Balance at end of the year	$22,441	$77,571	$116,234

At December 31, 2018, the Company had U.S. federal net operating loss (“NOL”) carryforwards of approximately $230.5 million. The Company had $224.5 million generated before December 31, 2017 which expire between 2027 and 2037, and $6.0 million are available to be carried forward for an indefinite period. The Company had state NOL carryforwards of approximately $269.1 million, $264.7 million which expire between 2025 and 2038 and $3.3 million are available to be carried forward for an indefinite period. The state tax credits in the amount of $0.8 million at December 31, 2018 are available to be carried forward for an indefinite period. The Production Tax Credits (“PTCs") in the amount of $90.9 million at December 31, 2018 are available for a 20-year period and expire between 2026 and 2038. The Foreign Tax Credits (“FTCs”) in the amount of $58.1 million at December 31, 2018 are available for a 10-year period and begin to expire in 2027.

The Company has recorded deferred tax assets for net operating losses, foreign tax credits, and production tax credits. Realization of the deferred tax assets and tax credits is dependent on generating sufficient taxable income in appropriate jurisdictions prior to expiration of the NOL carryforwards and tax credits. Based upon available evidence of the Company’s ability to generate additional taxable income in the future and historical losses in prior years, a valuation allowance in the amount of $22.4 million and $77.6 million is recorded against the U.S. deferred tax assets as of December 31, 2018 and 2017, respectively, as it is more likely than not that the deferred tax assets will not be realized. The overall decrease in the valuation allowance of $55.1 million is due to (i) write-off of foreign tax credits due to new refinements in 965 regulations and related valuation allowance on such credits (ii) true-up of foreign tax credits due to refined transition tax calculation and (iii) new available evidence that has refined the Company’s calculations in regards to the Tax Act which is expected to result in additional taxable income in the US. The Company is maintaining a valuation allowance of $22.4 million against a portion of the U.S. foreign tax credits and state NOLs that are expected to expire before they can be utilized in future periods.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On April 24, 2018, the Company acquired 100% of stock of USG for approximately $110 million. Under the acquisition method of accounting, the Company recorded a net deferred tax asset of $1.7 million comprised primarily of federal and state NOLs netted against deferred tax liabilities for partnership basis differences and fixed assets. The total amount of acquired federal and state NOLs, which are subject to limitations under Section 382, were $115.2 million and $49.9 million, respectively. A valuation allowance of $2.1 million has been recorded against such acquired state NOLs, as it is more likely than not that the deferred tax asset will not be realized.

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act makes significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax; (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

The Company applied the guidance of SAB 118 for the effects of the Tax Act in 2017 and throughout 2018. We completed our analysis to determine the effect of the Tax Act during December 2018. The Deemed Repatriation Tax (Transition Tax) is a tax on previously untaxed accumulated and current earnings and profits (E&P) of certain foreign subsidiaries. To determine the amount of the Transition Tax, we determined, in addition to other factors, the amount of post-1986 E&P of the relevant subsidiaries, as well as the amount of non-U.S. income taxes paid on such earnings. As a result of our initial analysis of the impact of the Act, we recorded a provisional amount of Transition Tax inclusion of $71.9 million. We completed our accounting for such items during 2018 and recorded a final Transition Tax inclusion of $64.2 million. The Company has sufficient NOLs to offset such earnings, therefore there is no resulting obligation due for such amount. In addition, the Company finalized its accounting related to the remeasurement of deferred taxes which resulted in a decrease of $3.5 million to the provisional benefit of $22.6 million recorded in 2017.

The FASB released guidance Staff Q&A, Topic 740, No. 5, that states a company can make an accounting policy election to either recognize deferred taxes related to GILTI or to provide for the GILTI tax expense in the year the tax is incurred as a period cost. The Company has elected to treat any GILTI inclusions as a period cost.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the deferred taxes on the balance sheet as of the dates indicated:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(Dollars in thousands)		
Non-current deferred tax assets	$113,760	$57,337	$—
Non-current deferred tax liabilities	(61,323)	(61,961)	(36,411)
Non-current deferred tax assets, net	52,437	(4,624)	(36,411)
Uncertain tax benefit offset (1)	(95)	(95)	—
	$52,342	$(4,719)	$(36,411)

(1) The non-current deferred tax asset has been reduced by the uncertain tax benefit of $0.1 million in accordance with ASU 2013-11, Income Taxes.

During 2017, the Company changed its intention to reinvest certain undistributed earnings of Ormat Systems Ltd., a wholly owned subsidiary in Israel. In the prior year, the Company distributed $396.0 million, of which $300.0 million was received in December 2017 and the remaining $96.0 million was received in December 2018. The Company recorded the tax impact of the distribution received in 2018 as part of the 2017 financials, including the 15% Israeli withholding tax in the amount of $14.4 million and corresponding foreign tax credit tax benefit, net of valuation allowance. In accordance with the Company's assertion to distribute certain earnings of Ormat Systems Ltd. as of December 31, 2018, the Company recorded a deferred tax liability on withholding taxes of approximately $8.1 million and foreign tax credits of $2.2 million on anticipated earnings to be remitted of $53 million. Foreign tax credits of $2.2 million is recorded on the withholding taxes which is subject to valuation allowance based on the Company's projected ability to utilize such foreign tax credits in the U.S. prior to the 10-year expiration period.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $211.3 million at December 31, 2018. It is the Company's intention to reinvest undistributed earnings of its foreign subsidiaries and thereby indefinitely postpone their remittance. Accordingly, the Company has not recorded a deferred tax liability on foreign earnings other than for OSL. The additional taxes on that portion of undistributed earnings which is available for dividends are not practicably determinable.

Uncertain tax positions

We are subject to income taxes in the U.S. (federal and state) and numerous foreign jurisdictions. Significant judgment is required in evaluating our tax positions and determining our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. We establish reserves for tax-related uncertainties based on estimates of whether, and the extent to which additional taxes will be due. These reserves are established when we believe that certain positions might be challenged despite evidence supporting the position. We adjust these reserves in light of changing facts and circumstances, such as the outcome of tax audits. The provision for income taxes includes the impact of reserve positions and changes to reserves that are considered probable.

At December 31, 2018 and 2017, there are $11.8 million and $8.9 million of unrecognized tax benefits that if recognized would affect the annual effective tax rate. Interest and penalties assessed by taxing authorities on an underpayment of income taxes are included as a component of income tax provision in the consolidated statements of operations and comprehensive income.

A reconciliation of our unrecognized tax benefits is as follows:

	Year Ended December 31,		
	2018	**2017**	**2016**
	(Dollars in thousands)		
Balance at beginning of year	$6,357	$4,609	$7,781
Additions based on tax positions taken in prior years	293	5	675
Additions based on tax positions taken in the current year	2,446	2,580	1,532
Reduction based on tax positions taken in prior years	(276)	(837)	(5,379)
Balance at end of year	$8,820	$6,357	$4,609

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company and its U.S. subsidiaries file consolidated income tax returns for federal and state purposes. As of December 31, 2018, the Company has not been subject to U.S. federal or state income tax examinations. The Company remains open to examination by the Internal Revenue Service for the years 2002-2017 and by local state jurisdictions for the years 2004-2017. These examinations may lead to ordinary course adjustments or proposed adjustments to our taxes or our net operating losses with respect to years under examination as well as subsequent periods.

The reduction of $0.3 million, $0.8 million, and $5.4 million in 2018, 2017, and 2016, respectively, was due to the statute of limitations expiration on certain tax positions as well as Ormat System's tax settlement as detailed below.

The Company's foreign subsidiaries remain open to examination by the local income tax authorities in the following countries for the years indicated:

Israel	2015-2018
Kenya	2012-2018
Guatemala	2014-2018
Honduras	2014-2018
Guadeloupe	2016-2018
New Zealand	2012-2018

Management believes that the liability for unrecognized tax benefits is adequate for all open tax years based on its assessment of many factors, including among others, past experience and interpretations of local income tax regulations. This assessment relies on estimates and assumptions and may involve a series of complex judgments about future events. As a result, it is possible that federal, state and foreign tax examinations will result in assessments in future periods. To the extent any such assessments occur, the Company will adjust its liability for unrecognized tax benefits.

Tax benefits in the U.S.

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. On February 9, 2018 the Bipartisan Budget Act of 2018 was enacted extending the PTC and ITC in lieu of PTCs for geothermal projects that begin construction before 2018. Geothermal projects that begin construction before 2018 and meet certain other “begun construction” rules qualify for 2.4 cents per kilowatt hour of PTCs for their first 10-years of operations; alternatively, the owner of the project may elect a 30% ITC in lieu of PTCs. In either case, under current tax rules for tax credits generated before January 1, 2018, any unused tax credit has a 1-year carry back and a 20-year carry forward.

If the Company claims the ITC, the Company’s “tax base” in the plant that it can recover through bonus or accelerated depreciation (if elected) must be reduced by half of the ITC. If the Company claims the PTC, there is no reduction in the tax basis for depreciation. Whether the Company claims the PTC or the ITC in lieu of PTC, for assets acquired and placed in service after September 27, 2017, the Company is permitted to fully expense the cost of qualified property (“bonus depreciation”). In later years, the first-year bonus depreciation deduction phases down, as follows:

80% for property placed in service after Dec. 31, 2022 and before Jan. 1, 2024.

60% for property placed in service after Dec. 31, 2023 and before Jan. 1, 2025.

40% for property placed in service after Dec. 31, 2024 and before Jan. 1, 2026.

20% for property placed in service after Dec. 31, 2025 and before Jan. 1, 2027.

The Company could also elect in lieu of bonus deprecation to depreciate most of the plant for tax purposes 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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Income taxes related to foreign operations

Guatemala — The enacted tax rate is 25%. Orzunil, a wholly owned subsidiary, was granted a benefit under a law which promotes development of renewable power sources. The law allows Orzunil to reduce the investment made in its geothermal power plant from income tax payable, which reduces the effective tax rate to zero. Ortitlan, another wholly owned subsidiary, was granted a tax exemption for a period of ten years ending August 2017. Starting August 2017, Ortitlan pays income tax of 7% on its Electricity revenues. The effect of the tax exemption in the years ended December 31, 2018, 2017, and 2016 is $2.0 million, $2.6 million, and $3.3 million, respectively ($0.04, $0.05, and $0.07 per share of common stock, respectively).

Israel — The Company's operations in Israel through its wholly owned Israeli subsidiary, Ormat Systems Ltd. ("Ormat Systems"), are taxed at the regular corporate tax rate of 26.5% in 2015, 25% in 2016, 24% in 2017 and 23% in 2018 and thereafter. 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. In January 2011, new legislation amending the Investment Law was enacted. Under the new legislation, a uniform rate of corporate tax would apply to all qualified income of certain industrial companies, as opposed to the current law's incentives that are limited to income from a "Benefited Enterprise" during their benefits period. According to the amendment, the uniform tax rate applicable to the zone where the production facilities of Ormat Systems are located would be 16% in 2014 and thereafter. Ormat Systems decided to irrevocably comply with the new law starting in 2011. In the event of distribution of a cash dividend out of retained earnings which were tax exempt due to prior benefits, Ormat Systems would have to pay tax in respect of the amount distributed. Since the exemptions are contingent upon nondistribution of dividends and since upon liquidation the Company will have to pay a 25% tax on exempt income, Ormat Systems recorded deferred tax liability at the rate of 25% in respect of the tax exempt income in 2004-2008. In the event that Ormat Systems fails to comply with the program terms, the tax benefits may be canceled and it may be required to refund the amount of the benefits utilized, in whole or in part, with the addition of linkage differences and interest.

Kenya - The Company's operations in Kenya are taxed at the rate of 37.5%. On September 11, 2015, Kenya's Income Tax Act was amended pursuant to certain provisions of the recently adopted Finance Act, 2015. Among other matters, these amendments retain the enhanced investment deduction of 150% under Section 17B of the Income Tax Act, extend the period for deduction of tax losses from 5 years to 10 years under Sections 15(4) and 15(5) of the Income Tax Act, and amend the effective date from January 1, 2016 to January 1, 2015 under Sections 15(4) and 15(5) of the Income Tax Act.

During the fourth quarter of 2018, the Kenya Revenue Authority ("KRA") notified the Company's subsidiary in Kenya of their intention to conduct an audit primarily focusing on related parties transactions for the years 2014-2017. The Company has submitted all of the required documents and further discussions with the KRA are currently underway.

As previously reported by the Company, the KRA conducted an audit related to the Company's operations in Kenya for fiscal years 2012 and 2013. On June 20, 2017, the Company has signed a Settlement Agreement with the KRA under which it paid approximately $2.6 million in principal for full settlement of all claims raised by the KRA during the audit. The principal amount that was paid in June 2017 was recorded as an addition to the cost of the power plants and is qualified for investment deduction at 150% under the terms of the settlement agreement. Additionally, as per the Settlement Agreement, the Company submitted a request for waiver on the applied interest in the amount of approximately $1.2 million, for which the Company recorded a provision to cover such a potential exposure.

Guadeloupe - The Company's operations in Guadeloupe are taxed at a rate of 34.43% in 2017, a maximum rate of 33.3% in 2018, a maximum rate 31% in 2019, a rate of 28% in 2020, 26.5% in 2021 and 25% in 2022.

Honduras - The Company's operations in Honduras are exempt from income taxes for the first ten years starting at the commercial operation date of the power plant.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Other significant foreign countries — The Company's operations in New Zealand are taxed at the rate of 28% that is applied on certain qualified costs basis in 2018 and 2017.

Income taxes related to U.S. tax legislation commonly referred to as the Tax Cuts and Jobs Act

On December 22, 2017, the U.S. government signed into law the Tax Act. The Tax Act makes significant changes to the U.S. tax code, including, but not limited to, (1) reducing the U.S. federal corporate income tax rate from 35 percent to 21 percent; (2) the transition of U.S. international taxation from a worldwide tax system to a territorial system (GILTI, BEAT, Dividends Received Deduction); (3) one-time transition tax on undistributed earnings of foreign subsidiaries as of December 31, 2017; (4) eliminating the corporate alternative minimum tax; (5) creating a new limitation on deductible interest expense; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 19 — BUSINESS SEGMENTS

In 2018, the Company started disclosing its energy storage and power load management business activity under the Other segment as such operations met the reportable segment criteria of ASC 280, Segment Reporting. As such, starting in 2018 the Company has three reporting segments: the Electricity segment, the Product segment and the Other segment. These segments are managed and reported separately as each offers different products and serves different markets. The Electricity segment is engaged in the sale of electricity from the Company’s power plants pursuant to PPAs. The Product segment is engaged in the manufacture, including design and development, of turbines and power units for the supply of electrical energy and in the associated construction of power plants utilizing the power units manufactured by the Company to supply energy from geothermal fields and other alternative energy sources. The Other segment is engaged in management of curtailable customer loads under contracts with U.S. retail energy providers and directly with large commercial and industrial customers as well as battery storage as a service.

Transfer prices between the operating segments were determined on current market values or cost plus markup of the seller’s business segment.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Summarized financial information concerning the Company's reportable segments is shown in the following tables, including, as further described under Note 1 to the consolidated financial statements, the Company's disaggregated revenues from contracts with customers as required by ASC 606:

	Electricity	Product	Other	Consolidated
	(Dollars in thousands)			
Year Ended December 31, 2018:				
Revenues from external customers:				
United States [1]	$305,962	$14,999	$7,645	$ 328,606
Foreign [2]	203,917	186,744	—	390,661
Net revenues from external customers	509,879	201,743	7,645	719,267
Intersegment revenues	—	48,817	—	48,817
Depreciation and amortization expense	126,181	4,311	1,741	132,233
Operating income (loss)	155,546	38,083	(8,519)	185,110
Segment assets at period end [3] (*)	2,896,938	156,942	67,470	3,121,350
Expenditures for long-lived assets	219,803	9,993	28,725	258,521
* Including unconsolidated investments	71,983	—	—	71,983
Year Ended December 31, 2017:				
Net revenues from external customers	$465,593	$224,483	$2,736	$ 692,812
Intersegment revenues	—	109,040	—	109,040
Depreciation and amortization expense	109,928	3,470	1,748	115,146
Operating income	157,613	50,543	(3,138)	205,018
Segment assets at period end [3] (*)	2,457,514	115,713	50,637	2,623,864
Expenditures for long-lived assets	252,581	6,653	—	259,234
* Including unconsolidated investments	34,084	—	—	34,084
Year Ended December 31, 2016 :				
Net revenues from external customers	$436,292	$226,299	$—	662,591
Intersegment revenues	—	56,075	—	56,075
Depreciation and amortization expense	102,698	3,279	—	105,977
Operating income	126,828	75,054	—	201,882
Segment assets at period end	2,204,444	257,125	—	2,461,569
Expenditures for long-lived assets	147,211	4,719	—	151,930

[1] Electricity segment revenues in the United States are all accounted under ASC 840, Leases, except for $26.9 million for the year ended December 31, 2018 that are accounted under ASC 606 starting in 2018. Product and Other

segment revenues in the United States are accounted under ASC 606, as further described under Note 1 to the consolidated financial statements.

(2) Electricity segment revenues in foreign countries are all accounted under ASC 840, Leases, and Product revenues in foreign countries are accounted under ASC 606 as further described under Note 1 to the consolidated financial statements.

(3) Electricity segment assets include goodwill in the amount of $20.0 million and $7.6 million as of December 31, 2018 and 2017, respectively. Other segment assets include goodwill in the amount of $0 million and $13.5 million as of December 31, 2018 and 2017, respectively. For further information on goodwill, see Note 9 – Intangible assets and goodwill to the consolidated financial statements.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Revenues:			
Total segment revenues	$719,267	$692,812	$662,591
Intersegment revenues	48,817	109,040	56,075
Elimination of intersegment revenues	(48,817)	(109,040)	(56,075)
Total consolidated revenues	$719,267	$692,812	$662,591
Operating income:			
Operating income	$185,110	$205,018	$201,882
Interest income	974	988	971
Interest expense, net	(70,924)	(54,142)	(67,389)
Foreign currency translation and transaction losses	(4,761)	2,654	(5,534)
Income attributable to sale of equity interest	19,003	17,878	16,503
Other non-operating income, net	7,779	(1,666)	(5,345)
Total consolidated income before income taxes and equity in income of investees	$137,181	$170,730	$141,088

The Company sells electricity and products for power plants and others, mainly to the geographical areas according to location of the customers, as detailed below. The following tables present certain data by geographic area:

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Revenues from external customers attributable to: [(1)]			

United States	$328,606	$301,132	$307,025
Indonesia	4,379	28,968	100,856
Kenya	119,094	110,243	109,270
Turkey	168,699	125,166	46,270
Chile	980	8,895	58,032
Guatemala	27,975	27,991	30,086
New Zealand	10,451	33,395	—
Other foreign countries	59,083	57,022	11,052
Consolidated total	$719,267	$692,812	$662,591

[1] Revenues as reported in the geographic area in which they originate.

203

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31,		
	2018	2017	2016
	(Dollars in thousands)		
Long-lived assets (primarily power plants and related assets) located in:			
United States	$1,696,439	$1,510,986	$1,414,523
Kenya	301,956	340,970	327,157
Other foreign countries	222,872	281,333	199,559
Consolidated total	$2,221,267	$2,133,289	$1,941,239

The following table presents revenues from major customers:

	Year Ended December 31,					
	2018 Revenues (Dollars in thousands)	%	2017 Revenues (Dollars in thousands)	%	2016 Revenues (Dollars in thousands)	%
Southern California Public Power [1]	$109,208	15.2	$70,100	10.1	$67,566	10.2
Sierra Pacific Power Company and Nevada Power Company [1][2]	116,149	16.1	125,424	18.1	127,226	19.2
Hyundai (3)	4,379	0.6	28,968	4.2	100,856	15.2
KPLC [1]	119,094	16.6	110,243	15.9	109,270	16.5

(1)Revenues reported in Electricity segment.

(2)Subsidiaries of NV Energy, Inc.

(3)Revenues related to the Sarulla project that are reported in Product segment.

204

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 20 — TRANSACTIONS WITH RELATED ENTITIES

There were no transactions between the Company and related entities, other than those disclosed elsewhere in these financial statements.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 21 — EMPLOYEE BENEFIT PLAN

401(k) Plan

The Company has a 401(k) Plan (the "Plan") for the benefit of its U.S. employees. Employees of the Company and its U.S. subsidiaries who have completed one year of service or who had one year of service upon establishment of the Plan are eligible to participate in the Plan. Contributions are made by employees through pretax deductions up to 60% of their annual salary. In 2018, 2017 and 2016, contributions made by the Company were matched up to a maximum of 4%, 3% and 2% of the employee's annual salary, respectively. The Company's contributions to the Plan were $1.6 million, $1.4 million, and $1.0 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Severance plan

The Company, through Ormat Systems, provides limited non-pension benefits to all current employees in Israel who are entitled to benefits in the event of termination or retirement in accordance with the Israeli Government sponsored programs. These plans generally obligate the Company to pay one month's salary per year of service to employees in the event of involuntary termination. There is no limit on the number of years of service in the calculation of the benefit obligation. The liabilities for these plans are recorded at each balance sheet date by determining the undiscounted obligation as if it were payable at that point in time. Such liabilities have been presented in the consolidated balance sheets as "liabilities for severance pay". The Company has an obligation to partially fund the liabilities through regular deposits in pension funds and severance pay funds. The amounts funded amounted to $10.6 million and $13.9 million at December 31, 2018 and 2017, respectively, and have been presented in the consolidated balance sheets as part of "deposits and other". The severance pay liability covered by the pension funds is not reflected in the financial statements as the severance pay risks have been irrevocably transferred to the pension funds. Under the Israeli severance pay law, restricted funds may not be withdrawn or pledged until the respective severance pay obligations have been met. As allowed under the program, earnings from the investment are used to offset severance pay costs. Severance pay expenses for the years ended December 31, 2018, 2017, and 2016 were $3.0 million, $3.2 million, and $2.3 million, respectively, which are net of income (including loss) amounting to $(1.1) million, $1.8 million, and $0.3 million, respectively, generated from the regular deposits and amounts accrued in severance funds.

The Company expects to pay the following future benefits to its employees upon their reaching normal retirement age:

	(Dollars in thousands)
Year ending December 31:	
2019	$ 3,677
2020	1,183
2021	1,470
2022	2,032
2023	1,246
2024-2028	4,262
Total	**$ 13,870**

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 retirement date. These amounts do not include amounts that might be paid to employees that will cease working with the Company before reaching their normal retirement age.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 22 — COMMITMENTS AND CONTINGENCIES

Geothermal resources

The Company, through its project subsidiaries in the U.S., controls certain rights to geothermal fluids through certain leases with the BLM or through private leases. Royalties on the utilization of the geothermal resources are computed and paid to the lessors as defined in the respective agreements. Royalty expense under the geothermal resource agreements were $21.6 million, $19.4 million, and $17.1 million for the years ended December 31, 2018, 2017, and 2016, respectively.

Letters of credit

In the ordinary course of business with customers, vendors, and lenders, the Company is contingently liable for performance under letters of credit totaling $229.6 million at December 31, 2018. Management does not expect any material losses to result from these letters of credit because performance is not expected to be required, and, therefore, is of the opinion that the fair value of these instruments is zero.

Purchase commitments

The Company purchases 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, the Company enters into agreements with contract manufacturers and suppliers that either allow them to procure goods and services based upon specifications defined by the Company, or that establish parameters defining the Company’s requirements.

At December 31, 2018, total obligations related to such supplier agreements were approximately $129.3 million (out of which approximately $36.1 million relate to construction-in-process). All such obligations are payable in 2019.

Grants and royalties

The Company, through Ormat Systems, had historically, through December 31, 2003, requested and received grants for research and development from the Office of the Chief Scientist of the Israeli Government. Ormat Systems is required to pay royalties to the Israeli Government at a rate of 3.5% to 5.0% of the revenues derived from products and services developed using these grants. No royalties were paid for the years ended December 31, 2018, 2017, and 2016. The Company is not liable for royalties if the Company does not sell such products and services. Such royalties are capped at the amount of the grants received plus interest at LIBOR. The cap at December 31, 2018 and 2017, amounted to $2.0 million and $1.9 million, respectively, of which approximately $1.0 million and $0.9 million, respectively, represents interest based on the LIBOR rate, as defined above.

Lease commitments

The Company entered into lease transactions for a fleet of vehicles. The lease transactions are classified as capital leases and the leased vehicles are classified under Property, Plant and Equipment in the total amount of $7.5 million and $3.6 million as of December 31, 2018 and 2017, respectively, representing the cost of vehicles under such transactions net of the related accumulated depreciation. The terms of the lease are monthly payments in equal installments over 5 years. The following table summarizes the minimum lease rentals for the following five years:

	(Dollars in thousands)
Year ending December 31:	
2019	$ 3,118
2020	3,318
2021	2,283
2022	1,941
2023	1,307
Total	**$ 11,967**

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is a schedule by years of future minimum rental payments required under operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2018.

Year ending December 31:	**(Dollars in thousands)**
2019	$ 7,771
2020	4,197
2021	3,475
2022	2,474
2023	1,603
Later years	9,292
Total minimum rental payments	**$ 28,812**

Contingencies

On May 21, 2018, a motion to certify a class action was filed in Tel Aviv District Court against Ormat Technologies, Inc. and 11 officers and directors, by the name of Heit vs. Ormat Technologies, et al. The alleged class is defined as "All persons who purchased Ormat shares on the Tel Aviv Stock Exchange between August 3, 2017 and May 13, 2018". The motion alleges that the Company violated Sections 31(a)(1) and 38C of the Israeli Securities Law because it allegedly: (1) misled investors by stating in its financial statements that it maintains effective internal controls over its accounting policies and procedures, however the Company's internal controls had material weaknesses which led to erroneous accounting in its 2017 unaudited quarterly reports that had to be restated, including adjustments to the Company’s net income and shareholders’ equity; and (2) failed to issue an immediate report in Israel until May 16, 2018, analogous to the report that was released in the United States on May 11, 2018 stating, inter alia, that the errors in its financial reports affected its balance sheet and would be remedied in its 2017 annual report. The Tel Aviv District Court has stayed the proceedings in Israel until a final decision in the U.S. putative class action case (Mac Costas below) of related subject matter is adjudicated. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

On June 11, 2018, a putative class action was filed by Mac Costas on behalf of alleged shareholders that purchased or acquired the Company's ordinary shares between August 8, 2017 and May 15, 2018 was commenced in the United

States District Court for the District of Nevada against the Company and its Chief Executive Officer and Chief Financial Officer. The complaint asserts claims against all defendants pursuant to Section 10(b) of the Exchange Act, as amended, and Rule 10b-5 thereunder and against its officers pursuant to Section 20(a) of the Exchange Act. The complaint alleges that the Company's Form 10-K for the years ended December 31, 2016 and 2017, and Form 10-Qs for each of the quarters in the nine months ended September 30, 2017 contained material misstatements or omissions, among other things, with respect to the Company’s tax provisions and the effectiveness of its internal control over financial reporting, and that, as a result of such alleged misstatements and omissions, the plaintiffs suffered damages. Following the Mac Costas claim filing, four additional complaints of similar content were filed by other complainants. As described below, this action has been consolidated with the derivative action of related subject matter. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

On September 11, 2018, the Klein derivative action was filed against the Company, our board and our CEO and CFO in the United States District Court for the District of Nevada, and on October 22, 2018, the Matthew derivative action was filed in the same court against the company, certain named present and former board members (Barniv, Beck, Boehm, Clark, Falk, Freedland, Granot, Joyal, Nishigori, Sharir, Stern and Wong) in the United States District Court, District of Nevada. Pursuant to a stipulation granted by the court, these derivative and the putative class actions described above (Mac Costas) have been consolidated, the derivative actions stayed pending a court ruling on an anticipated motion to dismiss the putative class actions, and service requirements waived by the Company and three US based directors. The Klein complaint asserts four derivative causes of action generally arising from Ormat's restatement of its financial statements: (i) the individual defendants allegedly breached their fiduciary duties by allowing the company to improperly report its financials; (ii) the individual defendants allegedly were unjustly enriched by being compensated while breaching their fiduciary duties; (iii) the individual defendants allegedly committed corporate waste in paying officers and directors and by incurring legal costs and potential liability; and (iv) the director defendants allegedly breached Section 14(a) of the Exchange Act in connection with the issuance of 2018 proxy. The Matthew complaint similarly alleges derivatively a breach of fiduciary duties, abuse of control, gross mismanagement, and corporate waste by the named directors. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Following the announcement of the Company's acquisition of USG, a number of putative shareholder class action complaints were initially filed on behalf of USG shareholders between March 8, 2018 and March 30, 2018 against USG and the individual members of the USG board of directors. All of the purported class action suits filed in Federal Court in Idaho have been voluntarily dismissed. The single remaining class action complaint is a purported class action filed in the Delaware Chancery Court, entitled Riche v. Pappas, et al., Case No. 2018-0177 (Del. Ch., Mar. 12, 2018). An amended complaint was filed on May 24, 2018 under seal, under a confidentiality agreement that was executed by plaintiff. The amended Riche complaint alleges state law claims for breach of fiduciary duty against former USG directors and seeks post-closing damages. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

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. The Company has filed a motion to intervene as an interested party in support of the BLM. The litigation was resolved and the settlement for an immaterial amount was approved by the Interior Board of Land appeals.

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 District Court granted plaintiffs' motion for joinder of HELCO as a co-defendant, and the case, which had been removed prior to the U.S. District Court for the District of Hawaii, was remanded back to the Third Circuit Court. The amended complaint purports 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 itself which it had filed on March 25, 2017 and agreed to the Company's request to add two third party defendants, who are, respectively, the distributor and manufacturer of the pressure release valve that failed to reseat during Hurricane Iselle. Discovery and depositions took place during the course of 2018 and, in January 2019, the case was again removed back to the U. S. District Court for the District of Hawaii. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

On March 29, 2016, a former local sales representative in Chile, Aquavant, S.A., filed a claim on the basis of unjust enrichment against Ormat's subsidiaries in the 27th Civil Court of Santiago, Chile. The claim requests that the court order Ormat to pay Aquavant $4.6 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 Ormat 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. The evidentiary period has concluded before the Civil Court on the basis of the court's "statement of facts" to be proved. The Company believes that it has valid defenses under law and intends to defend itself vigorously.

209

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 23 — QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Three Months Ended							
	Mar. 31, 2017	**June 30, 2017**	**Sept. 30, 2017**	**Dec. 31, 2017**	**Mar. 31, 2018**	**June 30, 2018**	**Sept. 30, 2018**	**Dec. 31, 2018**
	(Dollars in thousands, except per share amounts)							
Revenues:								
Electricity	$115,776	$110,896	$110,876	$128,045	$132,489	$122,179	$116,891	$138,320
Product	74,122	67,587	44,912	37,862	48,672	54,915	48,439	49,717
Other	--	881	1,397	458	2,862	1,205	1,150	2,428
Total revenues	189,898	179,364	157,185	166,365	184,023	178,299	166,480	190,465
Cost of revenues:								
Electricity	66,036	63,196	64,444	73,164	73,482	81,236	79,845	63,692
Product	49,452	43,432	32,218	26,992	33,726	37,573	35,669	33,729
Other	--	2,243	1,330	1,853	3,443	2,028	2,174	2,235
Total cost of revenues	115,488	108,871	97,992	102,009	110,651	120,837	117,688	99,656
Gross profit	74,410	70,493	59,193	64,356	73,372	57,462	48,792	90,809
Operating expenses:								
Research and development expenses	602	1,050	716	789	1,108	1,251	706	1,118
Selling and marketing expenses	4,363	4,090	3,630	3,517	3,699	3,712	8,578	3,813
General and administrative expenses	9,949	12,201	10,877	9,854	13,849	15,866	13,606	4,429
Impairment charge	--	--	--	--	--	--	--	13,464
Write-off of unsuccessful exploration activities	--	--	--	1,796	123	--	--	3
Operating income	59,496	53,152	43,970	48,400	54,593	36,633	25,902	67,982
Other income (expense):								
Interest income	244	362	255	127	113	189	214	458
Interest expense, net	(14,923)	(14,540)	(11,692)	(12,987)	(14,344)	(15,846)	(18,700)	(22,034)
Derivatives and foreign currency transaction gains (losses)	1,338	1,703	(1,001)	614	(1,599)	(529)	(383)	(2,250)

Income attributable to sale of tax benefits	6,157	4,356	3,506	3,859	7,361	3,556	4,066	4,020
Other non-operating income (expense), net	(92)	6	(1,592)	12	(20)	7,373	309	117
Income from continuing operations, before income tax and equity in earnings (losses) of investees	52,220	45,039	33,446	40,025	46,104	31,376	11,408	48,293
Income tax benefit (provision)	(11,004)	(32,765)	(6,224)	28,329	26,942	(29,105)	(1,184)	(31,386)
Equity in earnings (losses) of investees, net	(1,599)	(428)	337	(267)	1,210	388	(117)	6,182
Income from continuing operations	39,617	11,846	27,559	68,087	74,256	2,659	10,107	23,089
Net loss (income) attributable to noncontrolling interest	(4,423)	(3,206)	(3,599)	(3,467)	(4,748)	(3,002)	474	(4,869)
Net income (loss) attributable to the Company's stockholders	$35,194	$8,640	$23,960	$64,620	$69,508	$(343)	$10,581	$18,220
Earnings (loss) per share attributable to the Company's stockholders Basic:								
Net income	$0.71	$0.17	$0.48	$1.28	$1.37	$(0.01)	$0.21	$0.36
Diluted:								
Net income	$0.70	$0.17	$0.47	$1.27	$1.36	$(0.01)	$0.21	$0.36
Weighted average number of shares used in computation of earnings per share attributable to the Company's stockholders:								
Basic	49,680	49,771	50,367	50,607	50,614	50,623	50,645	50,691
Diluted	50,491	50,624	50,867	51,053	51,051	50,958	50,963	50,936

Table of Contents

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 24 — SUBSEQUENT EVENTS

Cash dividend

On February 26, 2019, the Company's Board of Directors declared, approved and authorized payment of a quarterly dividend of $5.6 million ($0.11 per share) to all holders of the Company's issued and outstanding shares of common stock on March 14, 2019, payable on March 28, 2019.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Disclosure Controls and Procedures

Evaluation of disclosure controls and procedure. Our management, including our Chief Executive Officer and Chief Financial Officer, have conducted the evaluation of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) required by Rules 13a-15(b) or 15d-15(b) under the Exchange Act, as amended. Based on that evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were not effective as of December 31, 2018 as a result of a material weakness in the Company's internal control over financial reporting that existed at December 31, 2017 and has not been remediated by the end of the period covered by this Annual Report on Form 10-K.

Management's Report on Internal Control over Financial Reporting

Our management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting as described in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended, or the Exchange Act. Internal control over financial reporting is defined as a process designed by, or under the supervision of, the issuer's principal executive and principal financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, 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 and includes those policies and procedures that: (1) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer, (2) Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer and (3) Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer'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 our conditions, or that the degree of compliance with our policies or procedures may deteriorate.

Evaluation of effectiveness of internal control over financial reporting Our 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, 2018 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, 2018 as a result of the material weakness in our internal control over financial reporting discussed below. 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 financial statements will not be prevented or detected on a timely basis.

Material weakness. 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 resulted in the restatements of the Company's unaudited condensed consolidated financial statements for the three and six months ended June 30, 2017, the three and nine months ended September 30, 2017, and the restatement of the Company's consolidated financial statements for the year ended December 31, 2017. Our management has concluded that this deficiency constitutes a material weakness in our internal control over financial reporting.

In Management's Report on Internal Control Over Financial Reporting included in our original Annual Report on Form 10-K for the year ended December 31, 2017, our management concluded that we did not maintain effective internal control over financial reporting as of December 31, 2017 because of the material weakness described above. As a result, we concluded that we did not maintain an effective internal control over financial reporting as of December 31, 2017, based on the criteria in Internal Control-Integrated Framework (2013) issued by the COSO.

Table of Contents

Remediation Plan

Subsequent to the evaluation made in connection with filing our Amended Annual Report on Form 10-K for the year ended December 31, 2017, our management, with the oversight of the Audit Committee of the Board of Directors, has continued the process of remediating the material weakness. In connection with the remediation process, we have:

- performed an enhanced risk assessment related to our internal controls over the accounting for income taxes;
- recruited additional tax personnel throughout the year, including a VP of Tax in January 2019;
- engaged an external tax and accounting firm to prepare and review our annual and quarterly income tax provision;
- implemented specific control procedures for the review, analysis and reporting of our income tax accounts, including control procedures of projections that support the deferred tax assets and liabilities;
- strengthened our income tax controls with improved documentation, communication and oversight.

We have made substantial progress in accordance with our remediation plan. However, the material weakness will not be considered remediated until the applicable controls operate for a sufficient period of time and management has concluded, through testing, that these controls are operating effectively. As such, since an appropriate period of time has not yet passed, we have determined that we did not maintain an effective internal control over financial reporting as of December 31, 2018 and have a material weakness in internal control over financial reporting in accounting for income taxes.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting in the fourth quarter of 2018 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. ***OTHER INFORMATION***

None.

Table of Contents

PART III

ITEM 10. ***DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE***

Information required by this Item and not set forth below is incorporated herein by reference to the Company's definitive proxy statement for the 2019 annual meeting.

The following table sets forth the name, age and positions of our directors, executive officers and persons who are executive officers of certain of our subsidiaries who perform policy making functions for us:

Name	Age	Position
Todd C. Freeland	52	Chairman of the Board of Directors and Independent Director (1)
Byron G. Wong	67	Independent Director (1)
Dan Falk	74	Independent Director (1)
Stanley B. Stern	61	Independent Director (2)
Yuichi Nishigori	62	Independent Director (2)
David Granot	71	Independent Director (2)
Ravit Barniv	55	Independent Director (3)
Stan H. Koyanagi	58	Independent Director (3)
Dafna Sharir	50	Independent Director (3)
Isaac Angel	62	CEO*
Doron Blachar	51	CFO*
Zvi Krieger	63	Executive Vice President—Electricity Segment*
Shlomi Argas	54	Executive Vice President—Product Segment and Operations*
Bob Sullivan	56	Executive Vice President - Business Development Sales & Marketing

* Performs the functions described in the table, but is employed by Ormat Systems

1)Denotes Class III Director – Term expiring at 2019 Annual Shareholders Meeting

2)Denotes Class I Director – Term expiring at 2020 Annual Shareholders Meeting

3)Denotes Class II Director – Term expiring at 2021 Annual Shareholders Meeting

Audit Committee

Information required by this Item and not set forth below is incorporated herein by reference to the Company’s definitive proxy statement for the 2019 annual meeting.

Table of Contents

ITEM 11. ***EXECUTIVE COMPENSATION***

Information required by this item and not set forth below is incorporated herein by reference to the Company's definitive proxy statement for the 2019 annual meeting.

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

Information required by this item and not set forth below is incorporated herein by reference to the Company's definitive proxy statement for the 2019 annual meeting.

ITEM 13. ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE***

Information required by this item and not set forth below is incorporated herein by reference to the Company's definitive proxy statement for the 2019 annual meeting.

ITEM 14. ***PRINCIPAL ACCOUNTANT FEES AND SERVICES***

Information required by this item is incorporated herein by reference to the Company's definitive proxy statement for the 2019 annual meeting.

Table of Contents

PART IV

ITEM 15. ***EXHIBITS, FINANCIAL STATEMENT SCHEDULES***

(a) *(1) List of Financial Statements*

See Index to Financial Statements in Part II, Item 8 of this annual report.

(2) List of Financial Statement Schedules

All applicable schedule information is included in our Financial Statements in Part II, Item 8 of this annual report.

(b) Exhibit Index. We hereby file, as exhibits to this Annual Report, those exhibits listed on the Exhibit Index immediately following the signature page hereto.

Exhibit No.	Document

(C) EXHIBIT INDEX

2.1	Agreement and Plan of Merger, dated January 24, 2018, by and among Ormat Nevada Inc., OGP Holding Corp. and U.S. Geothermal Inc., incorporated by reference to Exhibit 2.1 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 16, 2018.^
3.1	Third Amended and Restated Certificate of Incorporation, incorporated by reference to Appendix A to Ormat Technologies, Inc.'s Definitive Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on April 10, 2017.
3.2	

	Fourth Amended and Restated By-laws, incorporated by reference to Exhibit 3.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on January 2, 2013.
3.3	Amended and Restated Limited Liability Company Agreement of ORPD LLC, dated April 30, 2015, by and among Ormat Nevada Inc., Northleaf Geothermal Holdings LLC, and ORPD Holding LLC incorporated by reference to Exhibit 3.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2015.
4.1	Form of Common Share Stock Certificate, incorporated by reference to Exhibit 4.1 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
4.2	Form of Preferred Share Stock Certificate, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
4.3	Indenture for Senior Debt Securities, dated as of January 16, 2006, between Ormat Technologies, Inc. and Union Bank of California, incorporated by reference to Exhibit 4.2 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-3 (File No. 333-131064) filed with the Securities and Exchange Commission on January 6, 2006.
4.4	Indenture for Subordinated Debt Securities, dated as of January 16, 2006, between Ormat Technologies, Inc. and Union Bank of California, incorporated by reference to Exhibit 4.3 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-3 (File No. 333-131064) filed with the Securities and Exchange Commission on January 6, 2006.
4.5	Indenture of Trust and Security Agreement, dated September 23, 2011, among OFC 2 LLC, ORNI 15 LLC, ORNI 39 LLC, ORNI 42 LLC, HSS II, LLC, and Wilmington Trust Company, as Trustee and Depository, incorporated by reference to Exhibit 4.8 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2011.

Table of Contents

Exhibit No.	Document
10.1.1	Agreement for Purchase of Membership Interests in ORPD LLC, dated as of February 5, 2015, by and between Ormat Nevada Inc. and Northleaf Geothermal Holdings LLC is incorporated by reference to Exhibit 3.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2015.
10.1.2	Agreement for Purchase of Membership Interests in ORNI 37 LLC, dated as of November 22, 2016, by and between Northleaf Geothermal Holdings LLC and Ormat Nevada Inc., incorporated by reference to Exhibit 10.1.13 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.
10.1.3	Amended and Restated Limited Liability Company Agreement of Opal Geo LLC, dated as of December 16, 2016, by and between OrLeaf LLC and JPM Capital Corporation, incorporated by reference to Exhibit 10.1.14 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.
10.1.4	Equity Contribution Agreement, dated as of December 16, 2016, by and among JPM Capital Corporation, Ormat Nevada Inc. and OrLeaf LLC, incorporated by reference to Exhibit 10.1.15 to Ormat Technologies, Inc.'s Form 10-K filed with the Securities and Exchange Commission on March 1, 2017.
10.2.1	Power Purchase Contract dated, April 16, 1985, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.7 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.2	Amendment No. 1, dated as of October 23, 1987, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.8 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.2.3	Amendment No. 2, dated as of July 27, 1990, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.9 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.2.4	Amendment No. 3, dated as of November 24, 1992, between Southern California Edison Company and Second Imperial Geothermal Company, incorporated by reference to Exhibit 10.3.10 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

218

Table of Contents

Exhibit No.	Document
10.2.5	Power Purchase Contract, dated April 15, 1985, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.13 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) to the Securities and Exchange Commission on September 28, 2004.
10.2.6	Amendment No. 1, dated as of October 27, 1989, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.14 to Ormat Technologies, Inc. Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) to the Securities and Exchange Commission on September 28, 2004.
10.2.7	Amendment No. 2, dated as of December 20, 1989, between Mammoth Pacific and Southern California Edison Company, incorporated by reference to Exhibit 10.3.15 to Ormat Technologies, Inc. Registration Statement on Form S-1 (File No. 333-117527) to the Securities and Exchange Commission on July 20, 2004.
10.2.8	Interconnection Facilities Agreement, dated October 13, 1985, by and between Southern California Edison Company and Mammoth Pacific (II), incorporated by reference to Exhibit 10.3.20 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.9	Plant Connection Agreement for the Second Imperial Geothermal Company Power Plant No. 1, dated, October 27, 1992, by and between Imperial Irrigation District and Second Imperial Geothermal Company incorporated by reference to Exhibit 10.3.24 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.10	IID-SIGC Transmission Service Agreement for Alternative Resources, dated, October 27, 1992, by and between Imperial Irrigation District and Second Imperial Geothermal Company incorporated by reference to Exhibit 10.3.25 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.

Table of Contents

Exhibit No.	**Document**
10.2.11	IID-Edison Transmission Service Agreement for Alternative Resources, dated, September 26, 1985, by and between Imperial Irrigation District and Southern California Edison Company incorporated by reference to Exhibit 10.3.34 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.12	Plant Amendment No. 1, to IID-Edison Transmission Service Agreement for Alternative Resources, dated, August 25, 1987, by and between Imperial Irrigation District and Southern California Edison Company incorporated by reference to Exhibit 10.3.35 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.13	Agreement Addressing Renewable Energy Pricing and Payment Issues, dated June 15, 2001, by and between Second Imperial Geothermal Company QFID No. 3021 and Southern California Edison Company incorporated by reference to Exhibit 10.3.39 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.14	Amendment No. 1 to Agreement Addressing Renewable Energy Pricing and Payment Issues, dated November 30, 2001, by and between Second Imperial Geothermal Company QFID No. 3021 and Southern California Edison Company incorporated by reference to Exhibit 10.3.40 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

Table of Contents

Exhibit No.	Document
10.2.15	Purchase Power Contract, dated March 24, 1986, by and between Hawaii Electric Light Company and Thermal Power Company incorporated by reference to Exhibit 10.3.44 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.16	Firm Capacity Amendment to Purchase Power Contract, dated July 28, 1989, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.45 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.17	Amendment to Purchase Power Contract, dated October 19, 1993, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.46 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.18	Third Amendment to the Purchase Power Contract, dated March 7, 1995, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.47 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.19	Performance Agreement and Fourth Amendment to the Purchase Power Contract, dated February 12, 1996, by and between Hawaii Electric Light Company and Puna Geothermal Venture incorporated by reference to Exhibit 10.3.48 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.2.20	Power Purchase Agreement, dated October 20, 2016, between ONGP, LLC and Southern California Public Power Authority, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities Exchange Commission on June 1, 2017.
10.3.1	Ormesa BLM Geothermal Resources Lease CA 966 incorporated by reference to Exhibit 10.4.1 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.2	Ormesa BLM License for Electric Power Plant Site CA 24678 incorporated by reference to Exhibit 10.4.2 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.3	Geothermal Resources Mining Lease, dated February 20, 1981, by and between the State of Hawaii, as Lessor, and Kapoho Land Partnership, as Lessee incorporated by reference to Exhibit 10.4.3 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.4	Geothermal Lease Agreement, dated October 20, 1975, by and between Ruth Walker Cox and Betty M. Smith, as Lessor, and Gulf Oil Corporation, as Lessee incorporated by reference to Exhibit 10.4.4 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.5	Geothermal Lease Agreement, dated August 1, 1976, by and between Southern Pacific Land Company, as Lessor, and Phillips Petroleum Company, as Lessee incorporated by reference to Exhibit 10.4.5 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.6	Geothermal Resources Lease, dated November 18, 1983, by and between Sierra Pacific Power Company, as Lessor, and Geothermal Development Associates, as Lessee incorporated by reference to Exhibit 10.4.6 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

Table of Contents

Exhibit No.	**Document**
10.3.7	Lease Agreement, dated November 1, 1969, by and between Chrisman B. Jackson and Sharon Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.7 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.8	Lease Agreement, dated September 22, 1976, by and between El Toro Land & Cattle Co., as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.8 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.9	Lease Agreement, dated February 17, 1977, by and between Joseph L. Holtz, as Lessor, and Chevron U.S.A. Inc., as Lessee incorporated by reference to Exhibit 10.4.9 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.10	Lease Agreement, dated March 11, 1964, by and between John D. Jackson and Frances Jones Jackson, also known as Frances J. Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.10 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.11	Lease Agreement, dated February 16, 1964, by and between John D. Jackson, conservator for the estate of Aphia Jackson Wallan, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.11 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.12	Lease Agreement, dated March 17, 1964, by and between Helen S. Fugate, a widow, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.12 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.13	Lease Agreement, dated February 16, 1964, by and between John D. Jackson and Frances J. Jackson, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.13 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.14	Lease Agreement, dated February 20, 1964, by and between John A. Straub and Edith D. Straub, also known as John A. Straub and Edythe D. Straub, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.14 to Ormat Technologies, Inc.'s Registration

	Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.15	Lease Agreement, dated July 1, 1971, by and between Marie L. Gisler and Harry R. Gisler, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.15 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.16	Lease Agreement, dated February 28, 1964, by and between Gus Kurupas and Guadalupe Kurupas, husband and wife, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.16 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.17	Lease Agreement, dated April 7, 1972, by and between Nowlin Partnership, as Lessor, and Standard Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.17 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.18	Geothermal Lease Agreement, dated July 18, 1979, by and between Charles K. Corfman, an unmarried man as his sole and separate property, and Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.18 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.19	Lease Agreement, dated January 1, 1972, by and between Holly Oberly Thomson, also known as Holly F. Oberly Thomson, also known as Holly Felicia Thomson, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.19 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

Table of Contents

Exhibit No.	Document
10.3.20	Lease Agreement, dated June 14, 1971, by and between Fitzhugh Lee Brewer, Jr., a married man as his separate property, Donna Hawk, a married woman as her separate property, and Ted Draper and Helen Draper, husband and wife, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.20 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.21	Lease Agreement, dated May 13, 1971, by and between Mathew J. La Brucherie and Jane E. La Brucherie, husband and wife, and Robert T. O'Dell and Phyllis M. O'Dell, husband and wife, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.21 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 21, 2004.
10.3.22	Lease Agreement, dated June 2, 1971, by and between Dorothy Gisler, a widow, Joan C. Hill, and Jean C. Browning, as Lessor, and Union Oil Company of California, as Lessee incorporated by reference to Exhibit 10.4.22 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.23	Geothermal Lease Agreement, dated February 15, 1977, by and between Walter J. Holtz, as Lessor, and Magma Energy Inc., as Lessee incorporated by reference to Exhibit 10.4.23 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.24	Geothermal Lease, dated August 31, 1983, by and between Magma Energy Inc., as Lessor, and Holt Geothermal Company, as Lessee incorporated by reference to Exhibit 10.4.24 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.25	Geothermal Resources Lease, dated June 27, 1988, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.26 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.26	Amendment to Geothermal Resources Lease, dated January, 1992, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.27 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.

10.3.27	Second Amendment to Geothermal Resources Lease, dated June 25, 1993, by and between Bernice Guisti, Judith Harvey and Karen Thompson, Trustees and Beneficiaries of the Guisti Trust, as Lessor, and Far West Capital, Inc. and its Assignee, Steamboat Development Corp., as Lessee incorporated by reference to Exhibit 10.4.28 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.28	Geothermal Resources Sublease, dated May 31, 1991, by and between Fleetwood Corporation, as Lessor, and Far West Capital, Inc., as Lessee incorporated by reference to Exhibit 10.4.29 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.29	KLP Lease and Agreement, dated March 1, 1981, by and between Kapoho Land Partnership, as Lessor, and Thermal Power Company, as Lessee incorporated by reference to Exhibit 10.4.30 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.30	Amendment to KLP Lease and Agreement, dated July 9, 1990, by and between Kapoho Land Partnership, as Lessor, and Puna Geothermal Venture, as Lessee incorporated by reference to Exhibit 10.4.31 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.31	Second Amendment to KLP Lease and Agreement, dated December 31, 1996, by and between Kapoho Land Partnership, as Lessor, and Puna Geothermal Venture, as Lessee incorporated by reference to Exhibit 10.4.32 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 1 on Form S-1/A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
10.3.32	Participation Agreement, dated May 18, 2005, by and among Puna Geothermal Venture, SE Puna, L.L.C., Wilmington Trust Company, S.E. Puna Lease, L.L.C., AIG Annuity Insurance Company, American General Life Insurance Company, Allstate Life Insurance Company and Union Bank of California, incorporated by reference to Exhibit 10.4.33 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q/A filed with the Securities and Exchange Commission on December 22, 2005.
10.3.33	Project Lease Agreement, dated May 18, 2005, by and between SE Puna, L.L.C. and Puna Geothermal Venture, incorporated by reference to Exhibit 10.4.34 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q/A filed with the Securities and Exchange Commission on December 22, 2005.

Table of Contents

Exhibit No.	Document
10.4.1*	Amended and Restated Ormat Technologies, Inc. 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 11, 2014.
10.4.2**	Form of Incentive Stock Option Agreement to Ormat Technologies, Inc.'s 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.31.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 28, 2014
10.4.3*	Form of Freestanding Stock Appreciation Right Agreement to Amended and Restated Ormat Technologies, Inc.'s 2012 Incentive Compensation Plan, , incorporated by reference to Exhibit 10.31.3 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 28, 2014.
10.4.4*	Ormat Technologies, Inc.'s Annual Management Incentive Plan, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 29, 2016.
10.4.5*	Form of Restricted Stock Unit Agreement under the Amended and Restated Ormat Technologies, Inc. 2012 Incentive Compensation Plan, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities Exchange Commission on November 9, 2017.
10.4.6*	Ormat Technologies, Inc. 2018 Incentive Compensation Plan, incorporated by reference to Appendix A to Ormat Technologies, Inc.'s Definitive Proxy Statement on Schedule 14A filed on March 27, 2018.
10.4.7*	Form of Stock Appreciation Right Agreement under the Company's 2018 Incentive Compensation Plan for stock appreciation rights awarded to Mr. Isaac Angel, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed on May 9, 2018.
10.4.8*	Form of Restricted Stock Unit Agreement under the Company's 2018 Incentive Compensation Plan for restricted stock units awarded to Mr. Isaac Angel, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed on May 9, 2018.
10.4.9*	Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Employees-Time Based Units), incorporated by reference to Exhibit 10.5 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2018.

10.4.10*	Form of Stock Appreciation Right Grant Notice and Terms and Conditions (Employees), incorporated by reference to Exhibit 10.6 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on August 8, 2018.
10.4.11+*	Form of Restricted Stock Unit Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s 2018 Incentive Compensation Plan.
10.4.12+*	Form of Stock Appreciation Right Grant Notice and Terms and Conditions (Directors) to Ormat Technologies, Inc.'s 2018 Incentive Compensation Plan!
10.5.1*	Form of Indemnification Agreement incorporated by reference to Exhibit 10.11 to Ormat Technologies, Inc.'s Registration Statement Amendment No. 2 on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on October 20, 2004.
10.6.1	Note Purchase Agreement, dated December 2, 2005, among Lehman Brothers Inc., OrCal Geothermal Inc., OrHeber 1 Inc., OrHeber 2 Inc., Second Imperial Geothermal Company, Heber Field Company and Heber Geothermal Company, incorporated by reference to Exhibit 10.12 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2006.
10.6.2	Note Purchase Agreement, dated November 29, 2016, among ORNI 47 LLC, MUFG Union Bank, N.A., Munich Reinsurance America, Inc. and Munich American Reassurance Company, incorporated by reference to Exhibit 4.1 to Ormat Technologies Inc.'s Current Report on Form 8-K/A filed with the Securities and Exchange Commission on December 6, 2016.
10.7.1	Indenture dated as of December 8, 2005 among OrCal Geothermal Inc., OrHeber 1 Inc., OrHeber 2 Inc., Second Imperial Geothermal Company, Heber Field Company and Heber Geothermal Company and Union Bank of California, incorporated by reference to Exhibit 10.13 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2006.
10.7.2	First Supplemental Indenture dated as of June 14, 2006 amending the Indenture dated as of December 8, 2005 among OrCal Geothermal Inc., OrHeber 1 Inc., OrHeber 2 Inc., Second Imperial Geothermal Company, Heber Field Company and Heber Geothermal Company and Union Bank of California, incorporated by reference to Exhibit 10.13.2 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2006.
10.8	Guarantee dated as of December 8, 2005 among OrCal Geothermal Inc., OrHeber 1 Inc., OrHeber 2 Inc., Second Imperial Geothermal Company, Heber Field Company and Heber Geothermal Company, incorporated by reference to Exhibit 10.14 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2006.
10.14.1	Amended and Restated Power Purchase Agreement for Olkaria III Geothermal Plant, dated January 19, 2007, between OrPower 4 Inc. and The Kenya Power and Lighting Company Limited, incorporated by reference to

Exhibit 10.20.1 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 12, 2007.

10.14.2	Olkaria III Project Security Agreement, dated January 19, 2007, between OrPower 4 Inc. and The Kenya Power and Lighting Company Limited, incorporated by reference to Exhibit 10.20.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 12, 2007.

224

Table of Contents

Exhibit No.	Document
10.16	Joint Ownership Agreement for the Carson Lake Project, dated as of March 12, 2008, by and between Nevada Power Company and ORNI 16 LLC, incorporated by reference to Exhibit 10.24 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2008.
10.17	Sale and Purchase Agreement dated August 2, 2010, between ORNI 44 LLC and CD Mammoth Lakes I, Inc. and CD Mammoth Lakes II, Inc., incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2010.
10.18	Note Purchase Agreement, dated September 23, 2011, among OFC 2 LLC, ORNI 15 LLC, ORNI 39 LLC, ORNI 42 LLC, and HSS II, LLC, as Issuers, OFC 2 Noteholder Trust, as Purchaser, John Hancock Life Insurance Company (U.S.A.), as Administrative Agent, and the United States Department of Energy (DOE), as Guarantor, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 4, 2011.
10.19.1	Finance Agreement, dated as of August 23, 2012, between OrPower 4, Inc., an indirect wholly-owned subsidiary of Ormat Technologies, Inc., and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2012.
10.19.2	Amendment No. 1 to the Finance Agreement, dated as of August 23, 2012, between OrPower 4, Inc., an indirect wholly-owned subsidiary of Ormat Technologies, Inc., and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2012.
10.19.3	Loan Agreement, dated March 22, 2018, by and among Ormat Technologies, Inc. and Migdal Insurance Company Ltd., Migdal's Makefet Pension and Provident Funds Ltd. and Yozma Pension Fund of Self Employed Ltd., incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on June 19, 2018.
10.19.4	Finance Agreement, dated April 30, 2018 between Geotermica Platanares, S.A. DE C.V. and Overseas Private Investment Corporation incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on June 19, 2018.
10.19.5	Amendment to Finance Agreement, dated October 17, 2018 between Geotermica Platanares, S.A. DE C.V. and Overseas Private Investment Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed on November 8, 2018.

10.20	Equity Contribution Agreement with respect to ORTP, dated as of January 24, 2013, between Ormat Nevada, Inc., a wholly-owned subsidiary of Ormat Technologies, Inc., and JPM Capital Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on January 30, 2013.
10.21	Limited Liability Company Agreement of ORTP, LLC dated as of January 24, 2013, between Ormat Nevada, Inc., a wholly-owned subsidiary of Ormat Technologies, Inc., and JPM Capital Corporation, incorporated by reference to Exhibit 3.1 to Ormat Technologies, Inc. Current Report on Form 8-K to the Securities and Exchange Commission on January 30, 2013.
10.22.1*	Employment Agreement, dated as of February 11, 2014, between Ormat Technologies, Inc. and Isaac Angel, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on February 11, 2014.
10.22.2*	Employment Agreement, dated as of January 6, 2013, between Ormat Systems, Ltd. and Doron Blachar, incorporated by reference to Exhibit 10.30.2 to Ormat Technologies, Inc.'s Annual Report on Form 10-K filed with the Securities and Exchange on February 28, 2014.
10.23.1	JBIC Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, Japan Bank for International Cooperation and Mizuho Bank, Ltd., dated March 28, 2014, incorporated by reference to Exhibit 10.7 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.
10.23.2	Common Terms Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, Japan Bank for International Cooperation, Asian Development Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., ING Bank N.V., Tokyo Branch, National Australia Bank Limited, Mizuho Bank, Ltd., Mizuho Bank (USA), Pt. Bank Mizuho Indonesia, Société Générale, Société Générale Tokyo Branch, and Sumitomo Mitsui Banking Corporation, dated March 28, 2014, incorporated by reference to Exhibit 10.8 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.
10.23.3	Covered Lenders Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., Orsarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited, The Bank of Tokyo-Mitsubishi UFJ, Ltd., ING Bank N.V., Tokyo Branch, National Australia Bank Limited, Société Générale, Tokyo Branch, and Sumitomo Mitsui Banking Corporation, dated March 28, 2014, incorporated by reference to Exhibit 10.9 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.
10.23.4	ADB Facility Agreement, dated March 28, 2014, by and among Kyuden Sarulla Pte. Ltd., OrSarulla Inc., PT Medco Geopower Sarulla, Sarulla Operations Ltd, Sarulla Power Asset Limited and Asian Development Bank, dated March 28, 2014, incorporated by reference to Exhibit 10.10 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

10.23.5	Ormat Equity Support Deed, dated March 28, 2014, by and among Ormat International, Inc., Ormat Holding Corp., OrPower 11 Inc., OrSarulla Inc., Sarulla Operations Ltd, Mizuho Bank, Ltd. and Mizuho Bank (USA), dated March 28, 2014, incorporated by reference to Exhibit 10.11 to Ormat Technologies, Inc.'s Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 9, 2014.

225

Table of Contents

Exhibit No.	Document
10.24.1	Commercial Cooperation Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.1 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
10.24.2	Governance Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.2 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
10.24.3	Registration Rights Agreement, dated May 4, 2017, between Ormat Technologies, Inc. and ORIX Corporation, incorporated by reference to Exhibit 10.3 to Ormat Technologies, Inc.'s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 4, 2017.
21.1	Subsidiaries of Ormat Technologies, Inc., incorporated by reference to Exhibit 21.1 to Ormat Technologies, Inc.’s Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 28, 2006.
23.1+	Consent of Kesselman & Kesselman, Certified Public Accountants (Isr.), a member firm of PricewaterhouseCoopers International Limited, Independent Registered Public Accounting Firm.
23.2+	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
31.1+	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2+	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Material terms with respect to BLM geothermal resources leases incorporated by reference to Exhibit 99.1 to Ormat Technologies, Inc.’s Registration Statement Amendment No. 2 on Form S-1 (File No. 333-117527) filed

with the Securities and Exchange Commission on July 21, 2004.

99.2	Material terms with respect to BLM site leases incorporated by reference to Exhibit 99.2 to Ormat Technologies, Inc.'s Registration Statement on Form S-1 (File No. 333-117527) filed with the Securities and Exchange Commission on July 20, 2004.
99.3	Material terms with respect to agreements addressing renewable energy pricing and payment issues incorporated by reference to Exhibit 99.3 to Ormat Technologies, Inc.'s Registration Statement on Form S-1A (File No. 333-117527) filed with the Securities and Exchange Commission on September 28, 2004.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Management contract or compensatory plan in which directors and/or executive officers are eligible to participate.
+ Filed herewith.
^ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. We will furnish the omitted schedules to the SEC upon request.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ORMAT TECHNOLOGIES, INC.

By: /s/ Isaac Angel
Name: Isaac Angel
Title: Chief Executive Officer

Date: March 1, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated, on March 1, 2019.

Signature	Capacity
/s/ Isaac Angel Isaac Angel	Chief Executive Officer (Principal Executive Officer)
/s/ Doron Blachar Doron Blachar	Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ Todd Freeland Todd Freeland	Chairman of the Board of Directors
Stan Koyanagi	Director
/s/ Dan Falk Dan Falk	Director
/s/ David Granot David Granot	Director
/s/ Ravit Bar Niv	Director

Ravit Bar Niv

/s/ Yuichi Nishigori Yuichi Nishigori	Director
/s/ Dafna Sharir Dafna Sharir	Director
/s/ Stanley B. Stern Stanley B. Stern	Director
/s/ Byron Wong	Director

227