ORMAT TECHNOLOGIES, INC.
Form 10-K
March 12, 2007

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, 2006

or

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

Commission file number: 001-32347

ORMAT TECHNOLOGIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	88-0326081
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

6225 Neil Road, Suite 300, Reno, Nevada 89511-1136
(Address of principal executive offices)

Registrant's telephone number, including area code: (775) 356-9029

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

Title of each class	Name of each exchange on which registered
Ormat Technologies, Inc. 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of ''accelerated filer and large accelerated filer'' in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer

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, 2006, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $426,858,875 based on the closing price as reported on the New York Stock Exchange.

The number of outstanding shares of common stock of Ormat Technologies, Inc., as of February 28, 2007, was 38,111,108 par value $0.001 per share.

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, 2006.

ORMAT TECHNOLOGIES, INC.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2006

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Cautionary Note Regarding Forward-Looking Statements

This annual report includes ''forward-looking statements'' within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future, including such matters as our projections of annual revenues, expenses and debt service coverage with respect to our debt securities, future capital expenditures, business strategy, competitive strengths, goals, development or operation of generation assets, market and industry developments and the growth of our business and operations, are forward-looking statements. When used in this annual report, the words ''may'', ''will'', ''could'', ''should'', ''expects'', ''plans'', ''anticipates'', ''believes'', ''estim ''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 report are primarily located in the material set forth under the headings ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' contained in Part II, Item 7, ''Risk Factors'' contained in Part I, Item IA, and ''Notes to Financial Statements'' contained in Part II, Item 8 of this annual report, but are found in other locations as well. These forward-looking statements generally relate to our plans, objectives and expectations for future operations and are based upon management's current estimates and projections

of future results or trends. Although we believe that our plans and objectives reflected in or suggested by these forward-looking statements are reasonable, we may not achieve these plans or objectives. You should read this annual report completely and with the understanding that actual future results and developments may be materially different from what we expect due to a number of risks and uncertainties, many of which are beyond our control. We will not update forward-looking statements even though our situation may change in the future.

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

- significant considerations and risks discussed in this annual report;
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- geothermal resource risk (such as the heat content of the reservoir, useful life and geological formation);
- 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 authorization;
- construction or other project delays or cancellations;
- financial market conditions and the results of financing efforts;
- political, legal, regulatory, governmental, administrative and economic conditions and developments in the United States and other countries in which we operate;
- the enforceability of the long-term power purchase agreements for our projects;
- contract counterparty risk;
- weather and other natural phenomena;
- 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 and incentives for the production of renewable energy in the United States and elsewhere, 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;

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- competition from other similar geothermal energy projects, including any such new geothermal energy projects developed in the future, and from alternative electricity producing technologies;
- the effect of and changes in economic conditions in the areas in which we operate;
- market or business conditions and fluctuations in demand for energy or capacity in the markets in which we operate;
- the direct or indirect impact on our company’s business resulting from terrorist incidents or responses to such incidents, including the effect on the availability of and premiums on insurance; 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.

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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. The ‘‘OFC Senior Secured Notes’’ refers to the 8¼% Senior Secured Notes due 2020 that were issued in February 2004 by our subsidiary, Ormat Funding Corp. The ‘‘OrCal Senior Secured Notes’’ refers to the 6.21% Senior Secured Notes due 2020 that were issued in December 2005 by our subsidiary, OrCal Geothermal Inc.

Overview

We are a leading vertically integrated company engaged in the geothermal and recovered energy power business. We design, develop, build, own and operate clean, environmentally friendly geothermal and recovered energy-based power plants, in each case using equipment that we design and manufacture. We conduct our business activities in two business segments. In our Electricity Segment, we develop, build, own and operate geothermal and recovered energy-based power plants in the United States and geothermal power plants in other countries around the world and sell the electricity they generate. In our Products Segment, we design, manufacture and sell equipment for geothermal and recovered energy-based electricity generation, remote power units and other power generating units and provide services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy power plants.

Most of the projects 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. Therefore, electricity produced from geothermal energy sources contributes significantly less to local and regional incidences of acid rain and global warming than energy produced by burning fossil fuels. Geothermal energy is also an attractive alternative to other sources of energy as part of a national diversification strategy to avoid dependence on any one energy source or politically sensitive supply sources.

In addition to our geothermal energy business, we have developed and continue to develop products that produce electricity from recovered energy or so-called ‘‘waste heat.’’ We also own and are constructing new recovered energy projects to be owned and operated by us. Recovered energy or waste heat represents residual heat that is generated as a by-product of gas turbine-driven compressor stations and a variety of industrial processes, such as cement manufacturing, and is not otherwise used for any purpose. Such residual heat, that 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 emissions.

Company Contact and Sources of Information

We file annual, quarterly and periodic reports, proxy statements and other information with the Securities and Exchange Commission, which we refer to as 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., 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.

On May 31, 2006, we submitted to the New York Stock Exchange (NYSE) an Annual Written Affirmation, in the prescribed form and with no qualifications, regarding our compliance with the

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NYSE's Corporate Governance listing standards. In addition, our reports on Form 10-K, 10-Q and 8-K, and amendments to those reports are available at our website www.ormat.com for downloading, free of charge, as soon as reasonably practicable after these reports are filed with the SEC. Our Code of Business Conduct and Ethics, Code of Ethics Applicable to Senior Executives, Audit Committee Charter, Corporate Governance Guidelines, Nominating and Corporate Governance Committee Charter, Compensation Committee Charter, and Insider Trading Policy, as amended, are also available at our website address mentioned above. 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.

Our Power Generation Business

We own or control, and operate geothermal and recovered energy projects in the United States. We also own or control, and operate geothermal projects in Guatemala, Kenya, Nicaragua, and the Philippines. We continue to pursue opportunities to acquire and develop similar projects throughout the world. Most of our projects are located in regions where there is, or is expected to be, demand for additional generating capacity. We increased our net ownership interest in generating capacity by 51 megawatts (MW) between December 31, 2005 and December 31, 2006, resulting from the following: An increase of 19 MW, attributable to the acquisition of an additional 79.0% ownership interest in the Zunil project in Guatemala; an increase of 22 MW, attributable to the construction of the OREG 1 recovered energy project; an increase of 6 MW, attributable to the Gould geothermal power plant; and an increase of 5 MW, attributable to increased generating capacity of our existing geothermal power plants resulting from improvements to the geothermal well fields of some of our existing projects. We experienced a 1 MW reduction in generating capacity at our Brady project as a result of cooling. During the fourth quarter of 2006, we completed the construction of the Desert Peak 2 project in Nevada, which added 12 MW to our generating capacity. We have not yet declared this project commercially operational, which would trigger our obligation to provide the contracted generating capacity under the power purchase agreement.

In the year ended December 31, 2006, revenues from our electricity segment were $195.5 million, constituting approximately 72.7% of our total revenues in 2006. Revenues from the sale of electricity by our domestic projects were $162.8 million, constituting approximately 83.3% of our total revenues from the sale of electricity, and revenues from the sale of electricity by our foreign projects were $32.6 million, constituting approximately 16.7% of our total revenues from the sale of electricity.

The table below summarizes key information relating to our projects that are in operation as of December 31, 2006:

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Projects in Operation

Project	Location	Ownership[1]	Generating Capacity in MW[2]	Power Purchaser	Contracts Expiration
Domestic					
Ormesa Complex	East Mesa, California	100%	47	Southern California Edison Company	2017/2018
Heber Complex[3]	Heber, California	100%	82	Southern California Edison Company and Southern California Public Power Authority	2015/2023/2031
Steamboat Complex[4]	Steamboat, Nevada	100%	53	Sierra Pacific Power Company	2007[5]/2018/2022/2026
Mammoth Complex	Mammoth Lakes, California	50%	29	Southern California Edison Company	2014/2020
Puna	Puna, Hawaii	100%	30	Hawaii Electric Light Company	2027
Brady	Churchill County, Nevada	100%	19	Sierra Pacific Power Company	2022
Desert Peak 2[6]	Churchill County, Nevada	100%	12	Nevada Power Company	2027
OREG 1	North and South Dakota	100%	22	Basin Electric Power Cooperative	2031
Total For Domestic Projects in Operation:			294		
Foreign					
Leyte[7]	Philippines	80%	49	PNOC – Energy Development Corporation	2007
Momotombo	Nicaragua	100%	30	DISNORTE/DISSUR	2014
Zunil	Guatemala	100%	24	Instituto Nacional de Electricidad	2019
Olkaria III (Phase I)	Kenya	100%	13	Kenya Power and Lighting Co. Ltd.	2020[8]
Total For Foreign Projects in Operation:			116		
Total For Projects in Operation:			410		

(1) We own and operate all of our projects, except the Momotombo project in Nicaragua, which we do not own but which we control and operate through a concession arrangement with the Nicaraguan government, and the Mammoth and Leyte projects, in which we have a 50% and 80% ownership interest, respectively.

(2) References to generating capacity refers to the gross capacity less auxiliary power, in the case of all of our existing domestic projects and the Momotombo and Olkaria III projects (two of our foreign projects), and to the generating capacity that is subject to the ''take or pay'' power purchase agreements in the case of the Leyte and Zunil projects (another two of our foreign projects). We determine the generating capacity figures in any given year from available historical operational data of our operating projects taking into account resource capabilities. This column represents the generating capacity of the project, not our net ownership in such generating capacity.

In any given year, the actual power generation of a particular project may differ from that project's generating capacity due to operational issues affecting performance during that year. In 2006, the total actual power generation of the projects we operate in the U.S. was 1,998,660 MWh lower than the energy potential commensurate with our generating capacity due to operational factors discussed elsewhere in this annual report.

(3) The Heber Complex includes the Heber 1 and 2 projects and the Gould project.

(4) The Steamboat Complex includes the Steamboat 1 and 1A projects, the Steamboat 2 and 3 projects, the Burdette project and the Steamboat Hills project. The Galena 2 project, which is currently in final completion tests, will be added to the Steamboat Complex.

(5) The initial term of the power purchase agreement expired on December 31, 2006, but is being renewed automatically on an annual basis.

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(6) We have completed construction in the fourth quarter of 2006, but have not yet declared commercial operation under the power purchase agreement.

(7) The Leyte project will be transferred to the power purchasing utility in September 2007 for no consideration. This will reduce our foreign generation capacity by 49 MW.

(8) The power purchase agreement for the Olkaria III project will expire in 2020 or, if Phase II of the project is constructed and completed, 20 years from the completion of such Phase II. Phase II of this project involves the construction of additional facilities that we expect would add approximately 35 MW of generating capacity to this project. See ''Description of our Projects'' below.

The tables below summarize key information relating to the projects that are currently under construction and under development:

Projects under Construction

Project	Location	Ownership	Projected Commercial Operation Date	Projected Generating Capacity in (MW)	Power Purchaser	Contract Expiration
Steamboat Complex[1]	Washoe County,	100%	2007	14	Nevada Power Company/Sierra	2018/2027

	Nevada				Pacific Power Company	
Ormesa	East Mesa, California	100%	2007	10	Southern California Edison Company[2]	N/A
Amatitlan[3]	Guatemala	100%	2007	20	Instituto Nacional De Electricidad	2026
Heber South	East Mesa, California	100%	2007/2008	10	N/A	N/A
Puna	Puna, Hawaii	100%	2007/2008	8	N/A	N/A
Galena 3	Nevada	100%	2007/2008	17	Sierra Pacific Power Company	20 years following commercial operation date
OrSumas	Washington State	100%	2007/2008	5	Puget Sound Energy	20 years from Jan. 1st following commercial operation date
Brawley (Phase I)	Imperial County, California	100%	2008	50	N/A	N/A
Olkaria III (Phase II)	Kenya	100%	2008	35	Kenya Power and Lighting Co.	N/A[4]
Total				169		

[1] The new construction in the Steamboat Complex includes the 4 MW Steamboat Hills project and the 10 MW Galena 2 project.

[2] We have entered into an interim agreement with Southern California Edison Company and are currently negotiating a long-term power purchase agreement. See ''Description of our Projects'' below.

[3] We have completed construction in the fourth quarter of 2006, but have not yet declared commercial operation.

[4] The power purchase agreement for the Olkaria III Phase II project will expire 20 years from the completion of Phase II.

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Projects under Development

Project	Location	Ownership	Projected Commercial Operation	Projected Generating Capacity in	Power Purchaser	Contract Expiration

			Date	(MW)		
Carson Lake	Nevada	100%	2009	18 - 30	Nevada Power Company	20 years following commercial operation date
Buffalo Valley	Nevada	100%	2009	18 - 30	Nevada Power Company	20 years following commercial operation date
Brawley (Phase II)	Imperial County, California	100%	2009	50	N/A	N/A
OREG II		100%	2008/2009	27.5	Basin Electric Power Cooperative	N/A
Total				113.5 - 137.5		

Almost all of the revenues that we currently derive from the sale of electricity are pursuant to long-term power purchase agreements. Approximately 74.4% of our total revenues in the year ended December 31, 2006 from the sale of electricity by our domestic projects were derived from power purchasers that currently have investment grade credit rating. The purchasers of electricity from our foreign projects are either state-owned entities or private entities. We have obtained political risk insurance from the Multilateral Investment Guarantee Agency of the World Bank Group (MIGA) or from Zurich Re, a private sector political risk insurer, for all of our foreign projects (other than the Leyte project) in order to cover a portion of any loss that we may suffer upon the occurrence of certain political events covered by such insurance.

Development, Construction and Acquisition. We have experienced significant growth in recent years, principally through the acquisition of geothermal power plants from third parties and the expansion and enhancement of our existing projects, including the following: (i) during 2006 we completed the acquisition of an additional 79.0% ownership interest in the Zunil project in Guatemala which increased our ownership capacity by 19 MW, (ii) during the third quarter of 2006 we completed the construction of the Gould project, which added 6 MW to the Heber complex; (iii) in October 2006, we completed the construction of the first owned recovered energy power plant, OREG 1, which added 22 MW to our generating capacity; and (iv) during the third quarter of 2006 we completed the enhancement program at the Mammoth and Momotombo projects, which added 5 MW to our generating capacity. We currently expect to continue growing our power generation business through:

- the development and construction of new geothermal and recovered energy-based power plants;
- the expansion and enhancement of our existing projects;
- the acquisition of additional geothermal and other renewable assets from third parties; and
- the entry into geothermal leases for future development.

As part of these efforts, we regularly monitor requests for proposals from, and submit bids to, investor-owned and other electric utilities in the United States to provide additional generating capacity, primarily in the western United States where geothermal resources are generally concentrated. During the third quarter of 2006, we responded to several requests for proposals issued by different utilities interested in purchasing renewable energy and we have been informed that some of our proposals, covering approximately 150 MW of proposed capacity in Nevada, California and Idaho, have been short-listed for further evaluation. There can be no assurance, however, that we will be chosen from the short list or that we will succeed in negotiating power purchase agreements with the various utilities. We also

respond to international tenders issued by foreign state-owned electric

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utilities for the development, construction and operation of new geothermal power plants. In addition, we apply our technological expertise to upgrade the facilities of our existing geothermal power plants and to continuously monitor and manage our existing geothermal resources in order to increase the efficiency and generating capacity of such facilities.

We are currently in varying stages of development of new projects and construction of new and existing projects. Based on our current development and construction schedule, which is subject to change at any time and which may not be met in its entirety, we expect to declare commercial operation of the 12 MW Desert Peak 2 project during the first half of 2007 and we expect to add between 227 to 251 MW in generating capacity from geothermal and recovered energy power plants in the United States by the end of 2009. Outside of the U.S., we expect to declare commercial operation of the 20 MW Amatitlan project in Guatemala, during the first half of 2007, and to complete the construction of the 35 MW project in Kenya by the end of 2008.

We are a member in a consortium, which is in the process of developing a geothermal power project in Indonesia of approximately 300 MW that is expected to come on line in phases between 2010 and 2012. The consortium is currently negotiating a power purchase agreement with a local utility. We estimate that our minority interest equivalent will range between 45 MW to 60 MW.

Our Products Business

We design, manufacture and sell products for electricity generation and provide the related services described below. Generally, we manufacture products only against customer orders and do not manufacture products for our own inventory.

Power Units for Geothermal Power Plants. We design, manufacture and sell power units for geothermal electricity generation, which we refer to as Ormat Energy Converters or ‘‘OEC’’s. Our customers include contractors and geothermal plant owners and operators. We recently sold one of our air-cooled OEC units to Tauropaki Power Company of New Zealand

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’’ that is generated as a residual by-product of gas turbine-driven compressor stations 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. We recently signed a supply contract with ENAGAS S.A. of Madrid, Spain, for the supply of one OEC for a new Recovered Energy Generation (REG) power plant.

Remote Power Units and other Generators. We design, manufacture and sell fossil fuel powered turbo-generators with a capacity ranging between 200 watts and 5,000 watts, which operate unattended in extreme climate conditions, whether hot or cold. Our customers include contractors installing gas pipelines in remote areas. In addition, we design, manufacture and sell generators for various other uses, including heavy duty direct current generators. We have supplied remote power units to be installed on the Sakhalin pipeline in Russia.

Engineering, Procurement and Construction (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 the same customers described above that we target for the sale of our power units for recovered energy-based power generation. Unlike many other companies that provide EPC services, we have an advantage in that we are using our own manufactured equipment and thus have better control over the timing and delivery of required equipment and its costs. Recent examples of our construction activities include the design and construction of the Alliance REG plants in Canada and the Ngawha geothermal power plant in New Zealand.

In the year ended December 31, 2006, our revenues from our products business were $73.5 million, constituting approximately 27.3% of our total revenues.

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History

We were formed by Ormat Industries Ltd. (also referred to in this annual report as the ‘‘Parent,’’ ‘‘Ormat Industries,’’ ‘‘the parent company’’ or ‘‘our parent’’) in 1994 in the State of Delaware for the purpose of investing and holding ownership interests in power projects, as well as constructing and operating power plants owned by us and by third parties. Ormat Industries, which is based in Israel, is an international power systems company whose predecessor, Ormat Turbines Ltd., was founded in 1965 by Lucien and Dita Bronicki for the principal purpose of developing equipment for the production of a clean, renewable and generally sustainable form of energy. Ormat Industries sold to us its business relating to the manufacturing and sale of energy-related equipment and services. Following this sale, we now hold all of Ormat Industries’ power generation products business. Ormat Industries owns 64% of our outstanding common stock.

Industry Background

Geothermal Energy

Most of our projects in operation produce electricity from geothermal energy. Geothermal energy is a clean, renewable and generally sustainable energy source that, because it does not utilize combustion in the production of electricity, releases significantly lower levels of emissions, principally steam, than those that result from energy generation based on the burning of fossil fuels. Geothermal energy is derived from the natural heat of the earth when water comes sufficiently close to hot molten 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. The energy necessary to operate a geothermal power plant is typically obtained from several such wells which are drilled using established technology that is in some respects similar to that employed in the oil and gas industry. Geothermal production wells are normally located within approximately one to two miles of the power plant as geothermal fluids cannot be transported economically over longer distances due to heat and pressure loss. The geothermal reservoir is a renewable source of energy if 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 if the well field is properly operated. Geothermal energy projects typically have higher capital costs (primarily as a result of the costs attributable to well field development) but tend to have significantly lower variable operating costs, principally consisting of maintenance expenditures, than fossil fuel-fired power plants that require ongoing fuel expenses.

Geothermal Power Plant Technologies

Geothermal power plants generally employ either binary systems or conventional flash systems. In our projects, we also employ our proprietary technology of combined geothermal cycle systems. See ‘‘Our Technology’’.

Binary System

In a 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 heat exchanger, which heats a secondary working fluid which has a low boiling point. This is typically an organic fluid, such as isopentane or isobutene, which is vaporized and is used to drive the turbine. The organic fluid is then condensed in a condenser which may be cooled by air or by water from a cooling tower. The condensed fluid is then recycled back to the heat exchanger, closing the cycle within the sealed system. The cooled geothermal fluid is then reinjected back into the reservoir. The binary technology is depicted in the graphic below.

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Flash Design System

In a 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 in the plant, where any remaining water droplets are removed. This produces a stream of dry saturated steam, which drives a 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 through the removal system in order to optimize the performance of the steam turbines. The condensate is used to provide make-up water for the cooling tower. The hot brine remaining after separation of steam is injected back into the geothermal resource through a series of injection wells. The flash technology is depicted in the graphic below.

In some instances, the wells directly produce dry steam (the flashing occurring under ground). In such cases, the steam is fed directly to the steam turbine and the rest of the system is similar to the flash power plant described above.

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Market Opportunity

The geothermal energy industry in the United States experienced significant growth in the 1970s and 1980s, followed by a period of consolidation of owners and operators of geothermal assets in the 1990s. The industry, once dominated by large oil companies and investor-owned electric utilities, now includes several independent power producers.

During the 1990s, growth and development in the geothermal energy industry occurred primarily in foreign markets, and only minimal growth and development occurred in the United States. Since 2001, there has been renewed interest in geothermal energy in the United States as production costs for electricity generated from geothermal resources have become more competitive relative to fossil fuel-based electricity generation, due to the increasing cost of natural gas, and as legislative and regulatory incentives, such as state renewable portfolio standards, have become more prevalent.

Although electricity generation from geothermal resources is currently concentrated in California, Nevada, Hawaii and Utah, there are opportunities for development in other states such as Alaska, Arizona, Idaho, New Mexico and Oregon due to the availability of geothermal resources and, in some cases, a favorable regulatory environment in such states.

A 2006 forecast of the Western Governors Association (WGA) projects the addition of geothermal installations with generating capacity of approximately 13,000 MW by 2025, out of which 5,600 MW is expected to be added by 2015. This forecast is based on existing, known geothermal resources and does not take into account any positive effects on generating capacity resulting from new technology, such as enhanced utilization of existing geothermal bases and engineered geothermal systems (according to the WGA, Geothermal Taskforce Report from January 2006).

In January 2007, the Massachusetts Institute of Technology published a study that projects a potential of 100,000 MW of generating capacity from geothermal power plants if the development of enhanced geothermal systems is successful.

An additional factor fueling recent growth in the renewable energy industry is global concern about the environment. Power plants that use fossil fuels generate higher levels of air pollution and their emissions have been linked to acid rain and global warming. In response to an increasing demand for ‘‘green’’ energy, many countries have adopted legislation requiring, and providing incentives for, electric utilities to sell electricity generated from renewable energy sources. In the United States, Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Iowa, Maine, Maryland, Massachusetts, Minnesota, Montana, Nevada, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, Texas, Vermont, Washington, Wisconsin and the District of Colombia have all adopted renewable portfolio standards, renewable portfolio goals, or other similar laws requiring or encouraging electric utilities in such states to generate or buy a certain percentage of their electricity from renewable energy sources or recovered heat sources. Of these twenty-three states, fifteen states and the District of Columbia (including California, Nevada and Hawaii, where we have been the most active in our geothermal energy development and in which all of our U.S. geothermal projects are located) define geothermal resources as ‘‘renewables’’. A bill establishing renewable portfolio standards is currently before the Kansas legislature.

We believe that these legislative measures and initiatives present a significant market opportunity for us. For example, California generally requires that each investor-owned electric utility company operating within the state increase the amount of renewable generation in its resource mix by 2% per year so that 20% of its retail sales are procured from eligible renewable energy sources by 2010, ahead of the previous statutory mandated target of December 2017. Presently, approximately 11% of the electricity generated in California is derived from renewable resources (not counting hydroelectricity as renewable power). Nevada’s renewable portfolio standard requires each Nevada electric utility to obtain 9% of its annual energy requirements from renewable energy sources in 2007-2008, which requirement thereafter increases by 3% every two years until 2015, when 20% of such annual energy requirements must be provided from renewable energy sources or energy efficiency projects. At least three-quarters of the annual total requirements must come only from renewable energy projects.

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Hawaii's renewable portfolio standard requires each Hawaiian electric utility to obtain 8% of its net electricity sales from renewable energy sources by December 31, 2005, 10% by December 31, 2010 and 20% by December 31, 2020.

In addition, a new Act was signed into law in California to reduce carbon emissions to 1990 levels by 2020, representing a twenty-five percent reduction in greenhouse gas emissions. To accomplish this, the Act provides a framework for greenhouse gas emissions reductions through the use of emissions control technologies and other cost-effective reduction strategies. One such strategy may involve the use of market-based trading of emissions rights that will allow some greenhouse gas sources to over-control their emissions and sell the rights to their surplus reductions to other sources for whom the cost of reducing emissions would be significantly more costly. Although programs under the Act will take some time to develop, its requirements, particularly the creation of a market-based trading mechanism to achieve compliance with emissions caps, should be highly advantageous to in-state energy generating sources that have low carbon emissions such as geothermal energy.

The federal government also encourages production of electricity from geothermal resources through certain tax subsidies. We are permitted to claim approximately 10% of the cost of each new geothermal power plant in the United States as an investment tax credit against our federal income taxes. Alternatively, we are permitted to claim a ''production tax credit,'' which in 2006 was 1.9 cents per kWh and which is adjusted annually for inflation. The production tax credit may be claimed on the electricity output of new geothermal power plants put into service by December 31, 2008. Credit may be claimed for ten years on the output from any new geothermal power plants put into service prior to December 31, 2008. The owner of the project must choose between the production tax credit and the 10% investment tax credit described above. In either case, under current tax rules, any unused tax credit has a one-year carry back and a twenty-year carry forward. Whether we claim the production tax credit or the investment credit, we are also permitted 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. If we claim the investment credit, our ''tax base'' in the plant that we can recover through depreciation must be reduced by half of the tax credit; if we claim a production tax credit, there is no reduction in the tax basis for depreciation.

Collectively, these tax benefits (to the extent fully utilized) have a present value equivalent to approximately 30% to 40% of the capital cost of a new project.

The Kyoto Protocol entered into force on February 16, 2005, making the Protocol's emission targets for the 2008 to 2012 period legally binding on the more than 30 developed countries, including the EU members, Russia, Japan, Canada, New Zealand, Norway and Switzerland, all of which have ratified the Protocol. We expect that the effect of the Kyoto Protocol will be to encourage renewable energy installation outside of the United States, as the United States has not ratified the Kyoto Protocol.

Outside of the United States, the majority of power generating capacity has historically been owned and controlled by governments. During the past decade, however, many foreign governments have privatized their power generation industries through sales to third parties and have encouraged 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 countries have also adopted active governmental programs designed to encourage clean renewable energy power generation. For example, China, where we are currently trying to develop a project, has recently enacted a Renewable Energy Law (effective January 1, 2006) defining fiscal incentives, priority dispatching, preferential pricing and other supporting mechanisms, and has announced long-term targets for renewable energy capacity growth, including mandatory renewable portfolio standards for large generation utilities. Several Latin

American countries have rural electrification programs and renewable energy programs. For example, Guatemala, where our Zunil and Amatitlan projects are located, approved in November 2003 a law

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which creates incentives for power generation from renewable energy sources by, among other things, providing economic and fiscal incentives such as exemptions from taxes on the importation of relevant equipment and various tax exemptions for companies implementing renewable energy projects. We believe that these developments and governmental plans will create opportunities for us to acquire and develop geothermal power generation facilities internationally as well as create additional opportunities for us to sell our remote power units and other products.

In addition to our geothermal power generation activities, we have also identified recovered energy-based power generation as a significant market opportunity for us in North America and the rest of the world. We are initially targeting the North American market, where we expect that recovered energy-based power generation will be derived principally from compressor stations along interstate pipelines, from midstream gas processing facilities, and from processing industries in general. Several states, as well as the federal government, have recognized the environmental benefits of recovered energy-based power generation. For example, Nevada, Connecticut, New Mexico and Hawaii allow electric utilities to include recovered energy-based power generation in calculating their compliance with renewable portfolio standards. In addition, North Dakota, South Dakota and the U.S. Department of Agriculture (through the Rural Utilities Service) have approved recovered energy-based power generation units as renewable energy resources, which qualifies recovered energy-based power generators (whether in those two states or elsewhere in the United States) for federally funded, low interest loans. We believe that the European market has similar potential and we expect to leverage our early success in North America in order to expand into Europe and other markets worldwide. In North America alone, we estimate the potential total market for recovered energy-based generation to be approximately 1,000 MW.

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Competitive Strengths

Competitive Assets. Our assets are competitive for the following reasons:

- Contracted Generation. All of the electricity generated by our geothermal power plants is currently sold pursuant to long-term power purchase agreements, providing generally predictable cash flows.
- Baseload Generation. All of our geothermal power plants supply a part of the baseload capacity of the electric system in their respective markets, meaning that they operate to serve all or a part of the minimum power requirements of the electric system in such market on an around-the-clock basis. Because our projects supply a part of the baseload needs of the respective electric system and are only marginally weather dependent, we have a competitive

advantage over other renewable energy sources, such as wind power, solar power or hydro-electric power (to the extent dependent on precipitation), which compete with us to meet electric utilities' renewable portfolio requirements but which cannot serve baseload capacity because of the weather dependence and thus intermittent nature of these other renewable energy sources.

- Competitive Pricing. Geothermal power plants, while site specific, are economically feasible to develop, construct, own and operate in many locations, and the electricity they generate is generally price competitive as compared to electricity generated from fossil fuels or other renewable sources under existing economic conditions and existing tax and regulatory regimes.

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

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

Highly Experienced Management Team. We have a highly qualified senior management team with extensive experience in the geothermal power sector. Key members of our senior management team have worked in the power industry for most of their careers and average over 20 years of industry experience.

Technological Innovation. We own or have rights to use approximately 70 patents relating to various processes and renewable resource technologies. All of our patents are internally developed and therefore costs related thereto are expensed as incurred. Our ability to draw upon internal resources from various disciplines related to the geothermal power sector, such as geological expertise relating to reservoir management, and equipment engineering relating to power units, allows us to be innovative in creating new technologies and technological solutions.

No Exposure to Fuel Price Risk. A geothermal power plant does not need to purchase fuel (such as coal, natural gas, or fuel oil) in order to generate electricity. Thus, once the geothermal reservoir has been identified and estimated to be sufficient for use in a geothermal power plant and the drilling of wells is complete, the plant is not exposed to fuel price or fuel delivery risk.

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Business Strategy

Our strategy is to continue building a geographically balanced portfolio of geothermal and recovered energy assets, and to continue to be a leading manufacturer and provider of products and services related to renewable energy. We intend to implement this strategy through:

- Development and Construction of New Projects — continuously seeking out commercially exploitable geothermal resources, developing and constructing new geothermal and recovered energy-based power projects and entering into long-term power purchase agreements providing stable cash flows in jurisdictions where the regulatory, tax and business environments encourage or provide incentives for such development and which meet our investment criteria;
- Developing Recovered Energy Projects — establishing a first-to-market leadership position in recovered energy projects in North America and building on that experience to expand into other markets worldwide;
- Acquisition of New Assets — acquiring from third parties additional geothermal and other renewable assets that meet our investment criteria;
- Increasing Output from Our Existing Projects — increasing output from our existing geothermal power projects by adding additional generating capacity, upgrading plant technology, and improving geothermal reservoir operations, including improving methods of heat source supply and delivery; and
- 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.

Operations of our Power Generation Segment

How We Own Our Power Plants. We customarily establish a separate subsidiary to own interests in each power plant. Our purpose in establishing a separate subsidiary for each plant is to ensure that the 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 acquisition) of the relevant 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 our project. Our ability to transfer or sell our interest in certain projects may be restricted by certain purchase options or rights of first refusal in favor of our project partners or the project's power purchasers and/or certain change of control and assignment restrictions in the underlying project and financing documents. All of our domestic projects, with the exception of the Puna project, which is an Exempt Wholesale Generator (EWG), are Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA) and are eligible for regulatory exemptions from most provisions of the Federal Power Act (FPA) and certain state laws and regulations.

How We Obtain Development Sites and Geothermal Resources. For domestic projects, we either lease or own the sites on which our power plants are located. In our foreign projects, our lease rights for the 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 other agreement granting us the exclusive right to extract geothermal resources from specified areas of land, with the owners (or sublessors) of such land. A geothermal resource lease (or sublease) or a concession or other agreement will usually give 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 terms of the lease

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(or sublease) and concession agreement correspond to the terms of the relevant power purchase agreement. In certain other cases, we own the land where the geothermal resource is located, in which case there are no restrictions on its utilization.

How We Sell Electricity. In the United States, the purchasers of power from our projects are typically investor-owned electric utility companies. Outside of the United States, the purchaser is typically a state-owned utility or distribution company or a recently privatized state-owned entity and we typically operate our facilities pursuant to rights granted to us by a governmental agency pursuant to a concession agreement. In each case, we enter into long-term contracts (typically called power purchase agreements) for the sale of electricity or the conversion of geothermal resources into electricity. A project's revenues under a power purchase agreement usually consist of two payments: energy payments and capacity payments (although our recent power purchase agreements provide for energy payments only). Energy payments are normally based on a project's electrical output actually delivered to the purchaser measured in kilowatt hours, with payment rates either fixed or indexed to the power purchaser's ''avoided'' costs (i.e., the costs the power purchaser would have incurred itself had it produced the power it is purchasing from third parties, such as us). Capacity payments are normally calculated based on the generating capacity or the declared capacity of a project available for delivery to the purchaser, regardless of the amount of electrical output actually produced or delivered. In addition, most of our domestic projects located in California are eligible for capacity bonus payments under the respective power purchase agreements upon reaching certain levels of generation.

How We Operate and Maintain Our Power Plants. We usually employ one of our subsidiaries, (Ormat Nevada Inc., for our domestic projects) to act as operator of our power plants pursuant to the terms of an operation and maintenance agreement. 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 approach to plant management emphasizes the operational autonomy of our individual plant managers and staff to identify and resolve operations and maintenance issues at their respective projects; however, each project 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 project complex and provided by one operation and maintenance provider. This approach enables us to realize cost savings and enhances our ability to meet our project availability goals.

We currently operate and maintain approximately 410 MW of generating capacity (See Note (2) page 7 for an explanation of how we determine the generating capacity of our projects). Since our acquisitions in California, Hawaii and Nevada, as a result of our vertical integration, our proprietary technology and our operational and maintenance expertise, we have been successful in increasing the capacity, efficiency and performance of most of our acquired facilities and were able to use the staff required to operate these facilities more efficiently. For example, we have been able to increase the output of the Mammoth project by approximately 4 MW following its acquisition in December 2003. We have also increased the capacity of the Heber Complex by 13 MW (out of which 3 MW were used for auxiliary power).

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

How We Finance Our Power Plants. Historically, we have funded our projects with a combination of non-recourse or limited recourse debt, lease financing, parent company loans and internally generated cash. Such leveraged financing permits the development of projects with a limited amount of equity contributions, but also increases the risk that a reduction in revenues could adversely affect a particular project's ability to meet its debt obligations. Leveraged financing also means that distributions of dividends or other distributions by plant subsidiaries to us are contingent on compliance with financial and other covenants contained in the financing documents.

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

In the event of a foreclosure after a default, our project affiliate owning the project would only retain an interest in the assets, if any, remaining after all debts and obligations have been paid in full. In addition, incurrence of debt by a project may reduce the liquidity of our equity interest in that project because the interest is typically subject both to a pledge in favor of the project's lenders securing the project'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 the project affiliate in the form of certain limited obligations and contingent liabilities. These obligations and contingent liabilities take the form of guarantees of certain specified obligations, indemnities, capital infusions and agreements to pay certain debt service deficiencies. To the extent we become liable under such guarantees and other agreements in respect of a particular project, distributions received by us from other projects and other sources of cash available to us may be required to be used to satisfy these obligations. To the extent of these limited recourse obligations, creditors of a project financing of a particular project may have direct recourse to us.

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. The policies are issued by entities which specialize in such policies, such as MIGA, and from private sector providers, such as Zurich Re, AIG and other such companies. To date, our political risk insurance contracts are with MIGA and Zurich Re. Such insurance policies cover, in general and subject to the limitations and restrictions contained therein, 80% to 90% of our revenue loss derived from a specified governmental act such as confiscation, expropriation, riots, the inability to convert local currency into hard currency and, in certain cases, the breach of agreements. We have obtained such insurance for all of our foreign projects in operation except for the Leyte project.

Recent Developments

- In February 2007, the Nevada Public Utilities Commission approved two new 20-year power purchase agreements that two of our subsidiaries entered into on August 3, 2006 with Nevada Power Company, a subsidiary of Sierra Pacific Resources, for the sale of energy to be produced from the Carson Lake (near Fallon) and Buffalo Valley Power Plants, two new geothermal power plants to be built in Lander and Churchill Counties in northern Nevada. The Carson Lake and Buffalo Valley projects are both projected to come on line in late 2009. These new plants are expected to increase the total output supplied from us to Sierra Pacific Resources by between 36 and 60 MW.
- On January 31, 2007, we entered into two contracts with a combined value of $9.0 million with Enpower Green Energy Generation, Inc. for the supply of two OEC units for two REG plants to be located on the Duke Energy T South Pipeline System in British Columbia, Canada. The equipment is to be supplied within 13 to 14 months of February 27, 2007, the effective date of both contracts.

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- On January 19, 2007, our subsidiary developing the Olkaria III project entered into an Amended and Restated Power Purchase Agreement and a Project Security Agreement, with Kenya Power and Lighting Co. (KPLC), the Kenyan parastatal electricity transmission and distribution company, with respect to Phase II of the Olkaria III project. These agreements were executed after receipt of appropriate regulatory approvals from the Kenyan authorities. The construction of Phase II of the project is expected, upon completion, to add approximately 35 MW to the existing facility, bringing the project's total capacity to approximately 48 MW. Following completion of Phase II, total anticipated annual revenues from the project will be approximately $32 million.
- In January 2007, one of our subsidiaries entered into a Power Purchase Option Agreement with Basin Electric Power Cooperative (Basin Electric) regarding five new Recovered Energy Generation (REG) Power Plants along the Northern Border Pipeline in the States of Montana, North Dakota and Minnesota. According to the Option Agreement, Basin Electric will work towards fulfilling certain conditions with the goal to confirm that it is ready to enter into a definitive 25-year power purchase agreement. These conditions include the interconnection and rights to the site on which the power plants will be constructed. We have already secured the rights to the waste heat for two of the new power plants and will continue to work towards obtaining the rights to the remaining three new power plants. The approval for construction of the new power plants is expected during 2007 after both parties have fulfilled their prerequisite obligations under the Power Purchase Option Agreement.
- In January 2007, two of our subsidiaries entered into supply and engineering, procurement and construction contracts with Ngawha Generation Ltd., a subsidiary of Top Energy Limited for a new geothermal power plant in Ngawha, New Zealand. The contracts are for a total of approximately $20 million, with construction of the power plant expected to be completed within 20 months from the contract date. Top Energy Limited is an environmentally friendly, local electricity network company in New Zealand.
- In December 2006, one of our subsidiaries entered into geothermal leases in the North Brawley known geothermal resource area in Imperial County, California. These geothermal leases secured 1,270 acres and we are in discussion with other land owners in this area to secure additional leases. We expect to begin drilling activity to explore the resource upon receipt of the necessary drilling permits, which we expect will be granted in the first half of 2007.

- On December 19, 2006, we completed a sale of 2,500,000 shares of common stock to Lehman Brothers in a block trade at a price of $37.50 per share, under a shelf registration statement filed in early 2006. Net proceeds to us, after deducting underwriting fees and commissions and estimated offering expenses associated with the offering, were approximately $92.5 million.
- In November 2006, the California Public Utilities Commission (CPUC) approved several five-year agreements entered into with Southern California Edison (SCE) in May and June 2006 establishing new renewable energy pricing for our existing power purchase aqgreements . These new agreements fix the energy rates payable by SCE for the five-year period beginning May 1, 2007 for our Ormesa, Heber 1, Heber 2 and Mammoth geothermal projects located in California. Under the new agreements, the geothermal energy produced by these projects will be sold at an average fixed energy rate of $62.74 per MWh, starting with a rate of $61.50 per MWh for the first year, with an annual escalation of 1% thereafter. The new agreements will come into effect when the current Renewable Energy Pricing Agreement terminates on April 30, 2007. The new average energy rate of $62.74 per MWh will replace the existing rate of $53.70 per MWh. The capacity payment and capacity bonus under the respective power purchase agreement for each of the projects remain unchanged.
- During the third quarter of 2006, one of our subsidiaries signed geothermal lease agreements for leases of surface, mineral and geothermal rights, some with the Bureau of Land

Management and some with private owners, for: (i) approximately 7,500 acres in the Fallon area in Nevada; (ii) approximately 3,200 acres in the Fireball Ridge area in Nevada; (iii) approximately 16,400 acres in Gabbs Valley, Nevada; and (iv) approximately 640 acres in the Wildhorse prospect in Nevada.

- In October 2006, one of our subsidiaries completed the OREG 1 project along the Northern Border Pipeline in North Dakota and South Dakota. The OREG 1 project consists of four Recovered Energy Generation (REG) plants owned and operated by us with a total generating capacity of approximately 22 MW. Bismarck-based Basin Electric will purchase energy produced by these plants under a 25-year long-term power purchase agreement, which was announced in 2005.
- During the third quarter of 2006, we responded to several requests for proposals issued by different utilities interested in purchasing renewable energy. Recently, we were informed that some of our bids covering approximately 150 MW of proposed capacity in Nevada, California and Idaho have been short-listed for further evaluation. There can be no assurance, however, that we will be chosen from the short list or that we will succeed in negotiating power purchase agreements with the various utilities.
- On August 16, 2006, we acquired from two parties an additional 28.2% partnership interest (27.34% on a fully diluted basis assuming the exercise of an option by a third party) in Orzunil I de Electricidad, Limitada (Orzunil), which owns the Zunil project in Guatemala, thereby increasing our 71.8% ownership interest (69.67% on a fully diluted basis assuming the exercise of an option by a third party) in the Zunil Project to 100% (97% on a fully diluted basis, assuming the exercise of an option by a third party). The total purchase price for both acquisitions was $7.4 million (including acquisition costs of approximately $0.9 million). These acquisitions follow our acquisition of a 50.8% partnership interest (49.28% on a fully diluted basis assuming the exercise of an option by a third party) in Orzunil on March 13, 2006, whereby our subsidiary increased its then existing 21.0% ownership interest in the Zunil

Project to 71.8% (69.67% on a fully diluted basis assuming the exercise of an option by a third party). The purchase price we paid for the 50.8% acquisition was $15.4 million (including acquisition costs of approximately $0.6 million).

- In August 2006, the Nevada Public Utilities Commission approved the new 20-year power purchase agreement that our subsidiary entered into with Sierra Pacific Power Company in May 2006 for the sale of energy to be produced from the Galena 3 power plant, which is currently under construction. Under the new power purchase agreement, between 15 MW to 25 MW will be delivered from the Galena 3 project to SPPC for a fixed price of $61 per MWh, or $58 per MWh, assuming the project will be eligible for a production tax credit. These rates escalate at the beginning of each contract year by 1% and include the value of the renewable energy credits.
- In July 2006, a consortium consisting of our wholly owned subsidiary, a unit of Medco Energi Internasional Tbk (Indonesia's largest private oil and gas company), and Itochu Corp. of Japan won a tender issued by the Indonesian state-owned utility PT PLN (Persero) for the development of the Sarulla, North Sumatra, Indonesia geothermal power project on an independent power producer basis. Medco is the leader of the consortium, whose bid consisted of the completion of the development of the geothermal steam field, construction of the field piping systems and three Ormat designed and supplied power plants with a combined gross capacity of 340 MW, owning and operating the facilities and selling electricity to PLN under a 30-year power purchase agreement expected to be concluded within four months. Our specific responsibilities include the supply of the power plant and setting up and supervising the operations and maintenance of the plants, which will utilize our technology and equipment. The total project cost is projected to be about $600 million. The value of our scope of work for the supply of power plant equipment is expected to be approximately one-third of the total project cost. Release of the supply contracts to us will be made upon the financial closing of the transaction, expected to be 12 months from the effective date of

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the power purchase agreement. The Sarulla project is to be constructed over the next five years in three phases of 110 to 120 MW each, with the first power generating unit to be operational within 30 months and the last within 48 months from the financial closing. The project will be owned and operated by an Indonesian special purpose company (SPC) that will be established by the consortium members under the framework of a Joint Operating Contract with the concession holder, Pertamina (the state-owned oil and gas company). In addition to our responsibilities as the project's power plant equipment supplier and supervisor of operations and maintenance, we will participate as a minority shareholder in the SPC.

- On July 26, 2006, we entered into a contract valued at $4.0 million with ENAGAS S.A. of Madrid, Spain, for the supply of one OEC unit for a REG plant located in the ENAGAS gas compression station at Almendralejo, Spain. The equipment is to be supplied and installed within 19 months from the date of the contract.
- On July 20, 2006, we entered into a contract valued at $4.4 million with Geo X GmbH of Ludwigshafen, Germany, for the supply of one OEC unit for a geothermal power plant located in Landau, Germany. The equipment is to be supplied and installed within 17 months from the date of the contract.
- On June 7, 2006, one of our wholly-owned subsidiaries received supply and construction orders for three REG power plants on the Alliance Pipeline. Each facility will have a capacity

of 5 MW net and will convert the recovered waste heat from the exhaust of existing gas turbines into electricity. The contracts are in the total amount of $29.0 million. The three plants are expected to be commissioned in 2007 or early 2008.

- On April 26, 2006, we received a notice to proceed on an engineering, procurement and construction (EPC) contract to construct a geothermal power plant for the Raft River project in Idaho, for a total sales price of $20.2 million. Construction of the power plant is expected to be completed in the last quarter of 2007.
- On April 10, 2006, we completed a follow-on public offering of 3,500,000 shares of common stock at a price of $35.50 per share, under a shelf registration statement filed in early 2006. In addition, on April 17, 2006, the underwriters exercised their over-allotment option, thereby purchasing 525,000 additional shares of common stock at the same price. Net proceeds to us, after deducting underwriting fees and commissions and estimated offering expenses associated with the offering, were approximately $135.1 million.
- On April 4, 2006, we signed a contract to supply a 10 MW OEC power unit to PacifiCorp Energy in the Northwest region of the United States. The contract is in the amount of $11.5 million. The existing PacifiCorp plant, to which an additional OEC will be added, uses single-flash technology to produce approximately 23 MW of net power to the grid. The PacifiCorp plant utilizes only steam, which is separated from the brine and delivered to the plant, while the brine is reinjected into the ground. Ormat's technology enables recovery of heat from the brine before reinjection and PacifiCorp Energy will utilize this new OEC power unit to generate 10 MW of additional power in the OEC without additional resources or wells. The OEC power unit will be delivered in the second quarter of 2007 for installation adjacent to the existing plant.

Description of Our Projects

In the year ended December 31, 2006, revenues from the sale of electricity by our domestic geothermal projects were $162.8 million, constituting 83.3% of our total revenues from the sale of electricity, and revenues from the sale of electricity by our foreign geothermal projects were $32.6 million, constituting 16.7% of our total revenues from the sale of electricity. During 2006 we began selling electricity from our recovered energy projects, whose construction was completed in 2006.

The financing of certain of our projects and the terms of our power purchase agreements and certain other agreements related to our operations are further described in the ‘‘Description of Certain Material Agreements’’ section.

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Domestic Projects

Our projects in operation in the United States have a generating capacity of approximately 294 MW. Our current domestic projects are located in California, Nevada, Hawaii, North Dakota, and South Dakota. We also have projects under construction or enhancement in California, Nevada and Hawaii.

The Ormesa Complex

The Ormesa complex is located in East Mesa, Imperial County, California. The Ormesa complex consists of six

plants. The various plants commenced commercial operations between 1987 and 1989. The plants utilize binary and flash systems. The Ormesa complex has a generating capacity of 47 MW. Part of the electricity generated by two of the plants at the Ormesa complex, GEM 2 and GEM 3, is sold under an interim agreement (as discussed below) and part of it is used to provide auxiliary power for well field operations at the Ormesa complex. The Ormesa project sells its electrical output to Southern California Edison Company (Southern California Edison) under two separate power purchase agreements, which will expire in 2017 and 2018. We are currently in discussions with Southern California Edison to unitize the two power purchase agreements and to increase the amount of power being purchased by an additional 10 MW. The Ormesa project was acquired by us in April 2002, was initially refinanced with project finance debt from United Capital, and was refinanced again with the proceeds from the issuance by Ormat Funding of its Senior Secured Notes on February 13, 2004. The OFC Senior Secured Notes are collateralized by all of the assets of the Ormesa project (and any and all proceeds arising therefrom) and our project subsidiary, Ormesa LLC, the direct owner of the Ormesa project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed Ormat Funding's obligations under the OFC Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for a further description of the collateralization of the OFC Senior Secured Notes.

During 2006, we experienced a relatively high rate of well and pump failure at the Ormesa complex, resulting in increased operating costs and reduced revenues, and a lower availability of the Ormesa well field. As a result, we did not meet the required minimum capacity factor of 80% during the on-peak period for the months of June and September 2006. Consequently, we have been placed on probation for a period not to exceed 15 months. During the probation period, if we fail again to meet the minimum performance requirements, the capacity of the project may be permanently reduced, in which case Southern California Edison would be entitled to a refund. We believe that the risk of not meeting the minimum performance requirements during the probationary period and in the future is very low as we expect to increase the generating capacity of the Ormesa complex by 10 MW to a total of 57 MW by the end of the first quarter of 2007.

In connection with the power purchase agreements for the Ormesa complex, Southern California Edison has expressed its intent not to pay the contract rate for the power supplied by the GEM 2 and GEM 3 plants to the Ormesa complex. Southern California Edison contends that California ISO real-time prices should apply, while management believes that SP-15 prices quoted by NYMEX should apply. According to Southern California Edison's estimation, the amount under dispute is approximately $2.5 million. The parties have signed an Interim Agreement, whereby Southern California Edison will continue to procure the GEM 2 and GEM 3 power at the current energy rate of 5.37 Cents/kWh until May 1, 2007. In addition, a long-term power purchase agreement is expected to be entered into for the GEM 2 and GEM 3 power. The negotiations of the long-term power purchase agreement are still under way and there is no guarantee that it will be successfully completed. Management believes that such settlement agreement will not have a material financial impact on us.

The Heber Complex

The Heber complex consists of the Heber 1 project, the Heber 2 project and the Gould project.

The Heber 1 Project. The Heber 1 project is located in Heber, Imperial County, California. The Heber 1 project includes one power plant, which commenced commercial operations in 1985, and a

geothermal resource field. The plant utilizes a dual flash system and has a generating capacity of approximately 38 MW. The Heber 1 project sells its electrical output to Southern California Edison under a long-term power purchase agreement, which will expire in 2015. In certain circumstances, Southern California Edison and its affiliated entities have a right of first refusal to acquire the power plant. Upon satisfaction of certain conditions specified in the power purchase agreement and subject to receipt of requisite approvals and negotiations between the parties, our project subsidiary will have the right to demand that Southern California Edison purchase the power plant. The acquisition of the Heber 1 project in December 2003 was financed with equity and non-recourse debt from Beal Bank, and was refinanced with the proceeds from the issuance by OrCal Geothermal Inc. (OrCal) of its Senior Secured Notes on December 8, 2005. The OrCal Senior Secured Notes are collateralized by all of the assets of the Heber Complex (and any and all proceeds arising therefrom) and our project subsidiary, Heber Geothermal Company, the direct owner of the Heber 1 project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed OrCal's obligations under the OrCal Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for a further description of the collateralization of the OrCal Senior Secured Notes.

The Heber 2 Project. The Heber 2 project is also located in Heber, Imperial County, California. The Heber 2 project includes one power plant which commenced commercial operations in 1993. The plant utilizes a binary system and has a generating capacity of approximately 34 MW. The Heber 2 project sells its electrical output to Southern California Edison under a long-term power purchase agreement, which will expire in 2023. The acquisition of the Heber 2 project in December 2003 was financed with equity and non-recourse debt from Beal Bank, and was refinanced with the proceeds from the issuance by OrCal of its Senior Secured Notes on December 8, 2005. The OrCal Senior Secured Notes are collateralized by all of the assets of the Heber Complex (and any and all proceeds arising therefrom) and our project subsidiary, Second Imperial Geothermal Company, the direct owner of the Heber 2 project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed OrCal's obligations under the OrCal Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for a further description of the collateralization of the OrCal Senior Secured Notes.

The Gould Project. The Gould project is also located in Heber, Imperial County, California. The Gould project consists of a bottoming-cycle OEC at Heber 1 and additional Ormat Integrated Two Level Units (ITLU) at Heber 2 and has total generating capacity of 10 MW. The project sells its electrical output under a new long-term power purchase agreement with Southern California Public Power Authority for a fixed price, which in 2006 was $57.50/MWh, which escalates annually at a rate of 1.5%. This power purchase agreement will expire in 2031. The construction of the Gould project was financed with equity, and was included in the financing of OrCal's Senior Secured Notes issued on December 8, 2005. The OrCal Senior Secured Notes are collateralized by all of the assets of the Heber Complex (and any and all proceeds arising therefrom) and our project subsidiary, OrHeber 2 Inc., the direct owner of the Gould project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed OrCal's obligations under the OrCal Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for a further description of the collateralization of the OrCal Senior Secured Notes. Recently, our project subsidiary that owns the Gould project reached an agreement with Southern California Public Power Authority to eliminate the obligation under the power purchase agreement to share the production tax credits and in exchange to reduce the fixed price under the power purchase agreement by $2/MWh. We have undertaken to OrCal to make up the difference of $2/MWh such that its overall revenues from the project are not affected.

The Steamboat Complex

The Steamboat complex consists of the Steamboat 1/1A project, the Steamboat 2/3 project, the Burdette project and the Steamboat-Hills project.

The Steamboat 1/1A Project. The Steamboat 1/1A project is located in Steamboat Hills, Washoe County, Nevada. The Steamboat 1/1A project includes two power plants which commenced

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commercial operations in 1986 and 1988, respectively. The Steamboat 1/1A project utilizes a binary system and currently has a generating capacity of 2 MW. The Steamboat 1/1A project sells its electrical output to Sierra Pacific Power Company under two separate power purchase agreements. The Steamboat 1/1A project was acquired in June 2003 using internally generated cash, and was refinanced with the proceeds from the issuance by Ormat Funding of its Senior Secured Notes on February 13, 2004. The OFC Senior Secured Notes are collateralized by all of the assets of the Steamboat 1/1A project (and any and all proceeds arising therefrom) and our project subsidiary, Steamboat Geothermal LLC, the direct owner of the Steamboat 1/1A project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed Ormat Funding's obligations under the OFC Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for further description of collateralization of the OFC Senior Secured Notes.

The initial term of the Steamboat 1 power purchase agreement expired at the end of 2006 but we continue to sell electricity by an automatic extension of the power purchase agreement on a year-by-year basis. We are currently negotiating a renewal of the power purchase agreement for the years 2007 and 2008.

The Steamboat 2/3 Project. The Steamboat 2/3 project is also located in Steamboat Hills, Washoe County, Nevada. The Steamboat 2/3 project consists of two power plants which commenced commercial operations in 1992. The Steamboat 2/3 project utilizes a binary system and has a generating capacity of 24 MW. We have experienced protracted failures of two of the project's turbines, which were not manufactured by us, and we are in the process of replacing the problematic equipment with turbines of our own design and manufacture. The Steamboat 2/3 project sells its electrical output to Sierra Pacific Power Company under two separate power purchase agreements. The Steamboat 2/3 project was acquired in February 2004 using internally generated cash and proceeds from the issuance by Ormat Funding of its Senior Secured Notes on February 13, 2004. The OFC Senior Secured Notes are collateralized by all of the assets of the Steamboat 2/3 project (and any and all proceeds arising therefrom) and our project subsidiary, Steamboat Development Corp., the direct owner of the Steamboat 2/3 project, has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed Ormat Funding's obligations under the OFC Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for further description of collateralization of the OFC Senior Secured Notes.

The Burdette Project. The Burdette Project is located in Steamboat, Washoe County, Nevada. The Burdette project has a generating capacity of 21 MW. We completed the construction of this project in November 2005 and we reached commercial operation on February 28, 2006. The project sells and transfers its electrical output and transfers its renewable energy credits to Sierra Pacific Power Company under a power purchase agreement that has a 20-year term ending on December 31, 2026.

The Steamboat-Hills Project. The Steamboat Hills project is also located in Steamboat Hills, Washoe County, Nevada. The Steamboat Hills project is comprised of one plant and commenced commercial operations in 1988. The Steamboat Hills project utilizes a single flash system and water cooled condenser and has a generating capacity of 6 MW, although the capacity under the power purchase agreement is 12.5 MW. The Steamboat Hills project sells its electrical output to Sierra Pacific Power Company pursuant to a power purchase agreement. The project, under the predecessor owner, experienced difficulties operating at full capacity, among other reasons because of a well blow-out. We intend to increase the generating capacity of the Steamboat Hills project by an additional 4 MW in the first half of 2007, to take full advantage of the power purchase agreement. The Steamboat Hills project was acquired in May 2004 using internally generated cash.

The Mammoth Complex

The Mammoth complex is located in Mammoth Lakes, California. The Mammoth complex is comprised of three plants, which commenced commercial operations between 1985 and1990. The Mammoth complex utilizes a binary system and has a generating capacity of 29 MW, including 4 MW

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that we added during the course of 2006. Our project subsidiary, OrMammoth, Inc., owns a 50% partnership interest in Mammoth-Pacific, L.P., which owns 100% of the Mammoth complex. The other 50% partnership interest is owned by an unrelated third party. The Mammoth complex sells its electrical output to Southern California Edison under three separate power purchase agreements. Our 50% ownership interest in the Mammoth complex was acquired in December 2003 using internally generated cash and project finance debt from Beal Bank, and was refinanced with the proceeds from the issuance by Ormat Funding of its Senior Secured Notes on February 13, 2004. The OFC Senior Secured Notes are collateralized by a pledge of our 50% ownership interest in Mammoth-Pacific, L.P. and our project subsidiary, OrMammoth Inc., has jointly and severally with certain of our other subsidiaries fully and unconditionally guaranteed Ormat Funding's obligations under the OFC Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for further description of collateralization of the OFC Senior Secured Notes.

The Brady Complex

The Brady complex consists of the Brady project and the Desert Peak 2 project.

The Brady Project. The Brady project is located in Churchill County, Nevada and includes the Brady plant and the Desert Peak 1 plant. The Brady plant commenced commercial operations in 1992. The Desert Peak 1 plant, which previously formed part of the Brady complex, commenced commercial operations in 1985, but is currently not operational following its shut down, as described below. The Brady project has a generating capacity of approximately 19 MW, utilizing flash and binary systems, and sells its electrical output to Sierra Pacific Power Company under a long-term power purchase agreement that will expire in 2022. In the second half of 2006, following our conclusion that the continued operation of the Desert Peak 1 plant at the Brady complex was not economical, based on the high costs of repair and maintenance that would be required to keep the Desert Peak 1 plant operational, we shut down the Desert Peak 1 plant. We are replacing the disconnected Desert Peak 1 plant with one of the units of the new Desert Peak 2 project and have been supplying electricity generated by such unit of the Desert Peak 2 project to the Brady project such that the overall output from the Brady project and its performance under its power purchase agreement have not been affected by the Desert Peak 1 plant shut down. We are also in the process of drilling a new production well and redrilling another well, with the intent of restoring the Brady project's generating capacity to 19 MW during the second half of 2007.

The Brady project was acquired in June 2001 using internally generated cash and was refinanced with the proceeds from the issuance by Ormat Funding of its Senior Secured Notes on February 13, 2004. The OFC Senior Secured Notes are collateralized by all of the assets of the Brady project (and any and all proceeds arising therefrom) and our project subsidiary, Brady Power Partners, the direct owner of the Brady project, has jointly and severally with certain of our other subsidiaries, fully and unconditionally guaranteed Ormat Funding's obligations under the OFC Senior Secured Notes. See ''Management's Discussion and Analysis of Financial Condition and Results of Operations'' for a further description of the collateralization of the OFC Senior Secured Notes and certain other matters relating to the

Brady complex and the OFC Senior Secured Notes.

The Desert Peak 2 Project. The Desert Peak 2 project is located in Churchill County, Nevada (near the Brady project). The Desert Peak 2 project includes a water cooled unit and an air cooled unit, utilizing our OEC units. The aggregate generating capacity of the Desert Peak 2 project is 12 MW. The electrical output from the project will be sold, and renewable energy and environmental credits transferred, to Nevada Power Company under a power purchase agreement that has a 20-year term commencing on the January 1 following the commercial operation date of the project. We expect to declare commercial operation of the Desert Peak 2 project during the first half of 2007. Recently, we have been using a portion of the electrical output from the Desert Peak 2 project to supply the Brady project, as described above. As of February 2007, we no longer supply electricity generated by the Desert Peak 2 project to the Brady project.

The Puna Project

The Puna project is located in the Puna district, Big Island, Hawaii. The Puna plant commenced commercial operations in 1993. The Puna plant utilizes an Ormat geothermal combined cycle system,

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and has a generating capacity of 30 MW. The Ormat geothermal combined cycle system consists of a back pressure steam turbine, in which the lower pressure steam exhausted from the turbine is condensed in a binary system. This system assures a higher efficiency of geothermal steam, with a resulting lower steam rate, in resources producing steam above 150psi (10 bar), or even 100psi if the steam has a high non-condensable gas content. The Puna project sells its electrical output to Hawaii Electric Light Company under two power purchase agreements. Although the Puna project has significant geothermal resources, because of existing geological conditions, these resources are difficult to manage. In the past, the Puna project required extensive levels of investment mainly to address problems with the production and injection wells related to the geothermal resources. The Puna project was acquired in June 2004 with the proceeds of parent company loans and short-term bank loans. We completed operating lease transactions in respect of the project, as described under ‘‘Management’s Discussion and Analysis of Financial Condition and Results of Operations’’.

During the second half of 2006, we encountered a mechanical problem in two wells. This caused us to limit the output of the project to approximately 20 MW as a precautionary limit. During the first quarter of 2007, we were able to restore the output to 30 MW, the level of the project’s design capacity.

In addition, we intend to increase the output of the Puna project by an additional 8 MW through the addition of OEC units. We are in the process of negotiating a new power purchase agreement for the additional generating capacity that will be available as a result of such activities.

The OREG 1 Project

The OREG 1 project is a REG project that consists of four power plants constructed on gas compressor stations along a natural gas pipeline in North and South Dakota. The project came on line during the third quarter of 2006 and has a generating capacity of 22 MW. Our project subsidiary has entered into a 25-year power purchase agreement with Basin Electric Power Cooperative (Basin Electric) pursuant to which the project sells the electrical output to Basin Electric.

Foreign Projects

Our projects in operation outside of the United States have a generating capacity of approximately 113 MW. We also have projects under construction in Guatemala and Kenya.

The Leyte Project (The Philippines)

The Leyte project is located in the Philippines, on the Isle of Leyte. The Leyte project consists of four power plants. The Leyte plants utilize steam systems; one conventional flash steam plant and three ORMAT manufactured topping steam turbines and have a combined generating capacity of 49 MW. The ORMAT topping steam turbines generate additional power by using the reduction in pressure to the inlet of the conventional flash steam plant, situated downstream, necessitated when the existing steam field produced steam at a higher pressure than can be accommodated by the conventional flash steam plant. Our project subsidiaries have an 80% partnership interest in Ormat-Leyte Co. Ltd., which owns 100% of the Leyte project. The remaining 20% partnership interest in Ormat-Leyte Co. Ltd. is held by two unrelated third parties. In August 1995, following a build-operate-transfer agreement, which we refer to as BOT, international tender, Ormat Inc. (which later transferred its interest in the BOT agreement to Ormat-Leyte Co. Ltd.) entered into a BOT agreement with PNOC-Energy Development Corporation, a Philippine company wholly owned by Philippine National Oil Company, a government-owned company. Under the BOT agreement, the project will be transferred to PNOC-Energy Development Corporation in September 2007 for no consideration. We do not anticipate any material financial loss as a result of such transfer, although going forward this will reduce our foreign generation capacity by 49 MW. Ormat-Leyte Co. Ltd. has an outstanding non-recourse loan from the Export-Import Bank of the United States, the outstanding balance of which was $3.8 million as of December 31, 2006. The loan is due and payable in approximately equal quarterly installments through July 2007.

The Government of The Philippines has initiated the privatization of its electricity industry. However, we cannot foresee when such privatization may be completed. If such privatization is

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achieved in a manner that jeopardizes PNOC-Energy Development Corporation’s or its affiliate’s ability to comply with their obligations under the BOT agreement, the parties are required to negotiate an amendment to the power purchase agreement. Should they fail to reach an agreement, PNOC-Energy Development Corporation has the obligation (and our project subsidiary has the right to require PNOC-Energy Development Corporation) to buy out Ormat-Leyte Co. Ltd.’s rights in the project at a price based upon the net present value of the projected cash flow from the project for the remaining term of the BOT agreement.

The Momotombo Project (Nicaragua)

The Momotombo project is located in Momotombo, Nicaragua. The Momotombo project is comprised of one plant and a geothermal field. The plant was already in existence when we signed the concession agreement for the project in March 1999, and had commenced commercial operations in the mid-1980s utilizing a dual flash system. During 2006 we increased the output of the Momotombo project by 3 MW through a work-over of the project’s existing wells, bringing the generating capacity to approximately 30 MW. The Momotombo project has a power purchase agreement with Empresa Distribuidora de Electricidad del Norte (DISNORTE) and Empresa Distribuidora de Electricidad del Sur (DISSUR), two corporations which own the power distribution rights in Nicaragua. Our project subsidiary, which operates the Momotombo project, has an outstanding loan from Bank Hapoalim B.M., the outstanding balance of

which was $11.3 million as of December 31, 2006.

The Olkaria III Project — Phase I (Kenya)

The Olkaria III project is located in Naivasha, Kenya. The Olkaria III project is comprised of one plant, which commenced commercial operation in August 2000, and a geothermal field. The plant currently has a generating capacity of approximately 13 MW (Phase I). We are working on the construction of Phase II of this project which we expect, upon completion, will increase the generating capacity of the Olkaria III project to approximately 48 MW. A description of Phase II of this project is set forth below in ‘‘Projects under Development.’’ Phase I of the Olkaria III project utilizes a binary system. In November 1998, following an international tender, our project subsidiary entered into a power purchase agreement with the Kenya Power and Lighting Co. Ltd. (KPLC), the Kenyan parastatal electricity transmission and distribution company, which was recently amended and restated in January 2007 . Our project subsidiary leases the site on which the geothermal resources and the plant facilities are located from the Kenyan government, pursuant to an agreement which will expire in 2040. The Kenyan government granted our project subsidiary a license giving it 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 by us. The Kenyan Minister of Energy has the right to terminate or revoke the license in the event our project subsidiary ceases work in or under the license area during a period of six months, or has failed to comply with the terms of the license or the provisions of the law relating to geothermal resources. Our project subsidiary is obligated to pay the Kenyan government monthly fees and royalties based on the amount of power supplied to KPLC.

The Zunil Project (Guatemala)

The Zunil project is located in Zunil, Guatemala. The Zunil project is comprised of one plant which commenced commercial operations in 1999. The plant utilizes a binary system consisting of Ormat Energy Converters and has a generating capacity of 24 MW. The project is owned by Orzunil I de Electricidad, Limitada, which owns 100% of the Zunil project. Another of our subsidiaries provides operation and maintenance services to the project. The Zunil project sells its generating capacity to Instituto Nacional de Electrification pursuant to a power supply agreement. As of the date of this annual report, Orzunil I de Electricidad, Limitada has two senior outstanding non-recourse loans, one from International Finance Corporation (IFC) and the other from the Commonwealth Development Corporation (CDC), the aggregate total balance of which was, as of December 31, 2006, $19.4 million. The loans are due and payable in quarterly installments through November 2011. Each of the IFC and the CDC owned 14.1% of the issued and outstanding partnership interests of Orzunil I de

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Electricidad, Limitada. On March 13, 2006 and on August 16, 2006, we consummated the acquisition of an additional 50.8% and 28.2%, respectively, of the ownership interest in the Zunil project and thereby increased our 21% ownership interest to 100% (97% on a fully diluted basis assuming the exercise of an option by a third party).

Projects under Construction

We are in varying stages of construction or enhancement of projects, both domestic and foreign. Based on our current construction schedule, we expect to add new generating capacity of approximately 114 MW in the United States and approximately 55 MW throughout the rest of the world by the end of 2008 or early 2009. This amount will be reduced by the 49 MW (of which we own 80%) of the Leyte project. The following is a description of the projects currently

undergoing construction:

The Amatitlan Project (Guatemala)

Our project subsidiary has completed the construction of a geothermal power plant in Amatitlan, Guatemala on a ‘‘build, own and operate’’ or ‘‘BOO’’ basis. The project is currently in final completion tests. The project is comprised of one power plant, which will have a generating capacity of 20 MW, and has obtained the rights to various geothermal production and reinjection wells. The Amatitlan plant uses our Ormat Energy Converters.

The term of the power purchase agreement for the Amatitlan project is 20 years from the date of the commencement of operations at the power plant or 23 years from the date of commencement of the construction work, whichever is later. During a period of two years after the completion of the construction of the power plant, and subject to the signing of an additional agreement with the Instituto Nacional de Electrification and the result of a feasibility test, our project subsidiary may increase the power generating capacity of the power plant through the drilling of additional wells and adding another power plant by up to an aggregate of 50 MW. We anticipate that commercial operation of the Amatitlan project will be declared in the first half of 2007.

The local municipal authorities have claimed that a construction license is required for the project, while our local counsel has advised us that no such license is required under the applicable laws and regulations. We are challenging the claim of the local municipal authorities.

The Galena 2 Project (U.S.)

The construction of the Galena 2 project in Washoe County, Nevada is completed and we are in the start up phase. The project is expected to have a generating capacity of 10 MW. Our project subsidiary will sell electrical output from the plant, and transfer the renewable energy and environmental credits, to Nevada Power Company under a power purchase agreement with a 20-year term that will commence on the first day of the year following the commercial operation date of the plant. The power purchase agreement was signed as part of Nevada Power Company’s efforts to comply with Nevada’s renewable portfolio standards.

The Heber South Project (U.S.)

We have started the construction of a 10 MW power plant, which will be located in what is known as the Heber Known Geothermal Resource Area or Heber KGRA. The construction activity is expected to include the drilling of production and injection wells and the construction of an OEC unit. Completion is expected in the first half of 2008. The power purchase agreement for this addition to the Heber complex is still under negotiation.

The Galena 3 Project (U.S.)

We have started the construction of the Galena 3 project, which will be located in Washoe County, Nevada. The project will increase the output of the Steamboat Complex by 17 MW of power

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generation under a 20-year power purchase agreement with Sierra Pacific Power Company. We expect the construction, which will bring the total generating capacity of the Steamboat Complex to approximately 85 MW, to be

completed by the end of 2007 or the beginning of 2008.

The Brawley Phase I Project (U.S.)

We have started the construction of a 50 MW power plant, which will be located in the North Brawley known geothermal resource area in Imperial County, California. Drilling started in February 2007 and we are negotiating the power purchase agreement for this project.

The OrSumas Project

The OrSumas project is a REG plant currently in the construction stage and is expected to have a generating capacity of 5 MW. Our project subsidiary has entered into a 20-year power purchase agreement with Puget Sound Energy pursuant to which the project will sell its electrical output to Puget Sound Energy. The power plant will be constructed on a gas compressor station along the Northwest Pipeline in the State of Washington. Our engineering work has identified certain environmental issues on the proposed project site. We are currently in the midst of discussions with the pipeline company regarding these environmental issues for which we are not responsible. The outcome of these discussions may result in a delay or termination of the project activities.

The Olkaria III Project — Phase II (Kenya)

As previously noted, our project subsidiary in Kenya has been working towards the construction of Phase II of the Olkaria III project. As of the date of this report, our project subsidiary has drilled wells and commenced preliminary construction activities but has not begun any material construction activities with respect to Phase II. On January 19, 2007, we entered into an Amended and Restated Power Purchase Agreement and a Project Security Agreement with Kenya Power and Lighting Co. (KPLC), the Kenyan parastatal electricity transmission and distribution company, with respect to Phase II of the Olkaria III project. These agreements were executed after the receipt of appropriate regulatory approvals from the Kenyan authorities. The construction of the second phase of the project is expected, upon completion, to add approximately 35MW to the existing facility, bringing the project's total capacity to approximately 48MW. Following completion of Phase II, total anticipated annual revenues from the project will be approximately $32 million.

Under the Amended and Restated Power Purchase Agreement, the parties agreed to (i) shorten the construction period for Phase II to approximately twenty one months commencing from the deposit of the agreed collateral by KPLC, which occurred on February 7, 2007; (ii) change the technical configuration of Phase II such that the plant will use OEC units to generate electricity; and (iii) reduce the tariff payable by KPLC on the total capacity of the plant upon completion of Phase II.

Under the Project Security Agreement, KPLC provided a letter of credit in an amount equal to the value of four months of anticipated revenues from the project under the Amended and Restated Power Purchase Agreement (currently valued at approximately $8 million).

Other Projects

We are currently pursuing construction or enhancement activities in the following projects:

- Steamboat Hills project: We plan to complete the construction of an additional 4 MW during the first quarter of 2007; and
- Ormesa project: We plan to complete the construction of an additional 10 MW during the first quarter of 2007; and
- Puna project: We plan to add 8 MW through the construction of OEC units by the end of 2008 or early 2009. We are in discussions with Hawaii Electric Light Company for the sale of

additional electrical power from the Puna project.

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Projects under Development and Future Projects

We also have projects under development in the United States, China and Indonesia. 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 Carson Lake Project (U.S.)

We are currently developing the Carson Lake project, which will be located in Churchill County, Nevada. The project will deliver between 18 MW to 30 MW of power generation under a 20-year power purchase agreement with Nevada Power Company. We expect the construction to be completed during 2009. The leases for this project have been obtained through an agreement with the U.S. Department of the Navy, which will get 5% of the revenues as royalties during the first 20 years of operation.

The Buffalo Valley Project (U.S.)

We are currently developing the Buffalo Valley project, which will be on BLM leases located in Lander County, Nevada. The project will deliver between 18 MW to 30 MW of power generation under a 20-year power purchase agreement with Nevada Power Company. We expect the construction to be completed during 2009.

The OREG II Projects (U.S.)

We recently entered into a Power Purchase Option Agreement with Basin Electric Power Cooperative (Basin Electric) regarding five new REG Power Plants, with a total generating capacity of 27.5 MW, along the Northern Border Pipeline in the States of Montana, North Dakota and Minnesota. According to the Option Agreement, Basin Electric will work towards fulfilling certain conditions with the goal of confirming its readiness to enter into a definitive 25-year power purchase agreement. We have already secured the rights to the waste heat for two of the new power plants and will continue to work towards obtaining the rights to the remaining three new power plants. The approval for construction of the new power plants is expected during 2007.

The Brawley Phase II Project (U.S.)

If the results of the drilling activities we are currently undertaking in connection with the Brawley Phase I project will indicate the existence of sufficient geothermal resource, we plan to construct an additional 50 MW power plant, which will be located in the North Brawley known geothermal resource area in Imperial County, California, adjacent to Phase I of the Brawley project.

The Yunnan Project (China)

OrYunnan Geothermal Co., Ltd., which is a joint venture established between our project subsidiary and Yunnan Province Geothermal Development Co., Ltd., owns exclusive rights to develop all of the geothermal resources in Teng Chong County, Baoshan City, in Yunnan Province, southwest China. Our project subsidiary owns 85% of the interests in OrYunnan Geothermal Co. Ltd., which owns all of the ownership interests in the Yunnan project. The area of the

geothermal concession is approximately 65 square miles and is located approximately 200 miles southwest of Kunming, the provincial capital of Yunnan, and approximately 40 miles from the border with Myanmar. We estimate the potential of the geothermal resources in the concession area to be between 150 to 200 MW. Initially, our project subsidiary and its partner intend to develop a geothermal field and construct a power plant with a generating capacity of approximately 42 MW, which we estimated would require a capital investment of approximately CNY 776.9 million (approximately $99.6 million calculated at the prevailing exchange rate on December 31, 2006). Our project subsidiary is awaiting Yunnan Provincial Government approval, following which negotiations with the provincial utility company towards the signing of a power purchase agreement may conclude. Following the approval of the Yunnan Provincial Government, the electricity feed-in tariffs would still require central government approval.

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Such tariffs will be based on the implementing regulations to be announced shortly. On May 29, 2002, our project subsidiary entered into a memorandum of understanding, which we refer to as an MOU, regarding the main terms of the power purchase agreement and other major project agreements with Yunnan Electric Power Co., Ltd., a state-owned utility company, concerning the purchase of electric power by the utility company from our project subsidiary on a 30-year basis and the related interconnection arrangements. The MOU estimated that the commercial operation date of the plant was to be January 1, 2006. However, we have been in the development stage of the OrYunnan Project for several years and this date will have to be extended for an appropriate period following the completion of the Chinese central government's approval.

The Sarulla Project (Indonesia)

We are a member of a consortium, which is in the process of developing a geothermal power project in Indonesia of approximately 300 MW that is expected to come on line in phases between 2010 and 2012. We estimate that our minority interest equivalent will range between 45 MW to 60 MW.

Exploration Activity

In addition to the geothermal projects under construction and development, we have various leases for geothermal resources, in which we have started exploration activity. These geothermal resources include the following:

- Grass Valley — Lander County, NV;
- Jersey Valley — Pershing County, NV;
- Magic Hot Springs — Blaine & Camas Counties, Idaho;
- Fireball Ridge — Churchill County, NV;
- Gabbs Valley — Nye County, NV;
- Rock Hills — Esmeralda County, NV.

Our exploration activity is intended to provide us with an indication and better understanding of the availability of geothermal resources in the areas covered by these leases and will enable us to make a decision regarding their development. We do not expect that our exploration activity will lead to commercial projects in each case.

Development Inventory

In addition to the geothermal projects under construction, development or exploration, we have various geothermal leases for future development in the United States and other development rights outside of the United States. These geothermal leases and rights include the following:

- Oregon — one site;
- California — three sites;
- Nevada — three sites;
- Hawaii — one site;
- Idaho — three sites;
- Texas — several leases; and
- Outside of the United States — two sites.

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Operations of our Products Segment

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

The consideration for the power units is usually paid in installments, in accordance with milestones set in the supply agreement. Sometimes we agree to provide the purchaser with spare parts (or alternatively, with a non-exclusive license to manufacture such parts). We provide the purchaser with at least a 12-month warranty for such products. We usually also provide the purchaser (often, upon receipt of advances made by the purchaser) with a guarantee, which expires in part upon delivery of the equipment to the site and fully expires at the termination of the warranty period. The guarantees are at times covered by letters of credit. Ormat has not received any claims under the performance guarantees to date.

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’’ that is generated as a residual by-product of gas turbine-driven compressor stations 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. We view recovered energy generation as a significant market opportunity for us, and plan to utilize two different business models in connection with such business opportunity. The first, which is similar to the model utilized in our geothermal power generation business, consists of the development, construction, ownership and operation of recovered energy-based generation power plants. In this case, we will enter into agreements to purchase industrial waste heat, and into long-term power purchase agreements with off-takers to sell the electricity generated by the recovered energy generation unit that utilizes such industrial waste heat. We expect that the power purchasers in such cases will be investor-owned electric utilities or local electrical cooperatives. In early 2006, we signed a supply contract with UltraTech Cement Ltd. in Mumbai, India for the supply of one OEC for a new REG power plant.

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

recovered energy project is an example of such a model. There, we installed one of our recovered energy-based generation units at Enterprise Product's Neptune gas processing plant in Louisiana. The unit utilizes exhaust gas from two gas turbines at the plant and is providing electrical power that is consumed internally by the facility (although a portion of the generated electricity is also sold to the local electric utility). Recently we signed two agreements (with ICQ and Ultratech) for the supply of Ormat OEC systems for Recovered Energy Generation plants.

Our recovered energy generation units, if structured properly, may be eligible for favorable tax treatment, such as the seven year modified accelerated cost recovery under relevant U.S. federal tax rules.

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

Engineering, Procurement and Construction (EPC) of Power Plants. We engineer, procure and construct, as an EPC contractor, geothermal and recovered energy power plants on a turnkey basis,

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

We also design and construct the recovered energy generation units on a turnkey basis, and may provide a long-term agreement to supply non-routine maintenance for such units. Our customers are interstate natural gas pipeline owners and operators, gas processing plant owners and operators, cement plant owners and operators and companies engaged in the process industry. For example, recently we entered into supply and construction contracts with Alliance pipeline in Western Canada for an Ormat Recovered Energy Generation power plant.

In connection with the sale of our power units for geothermal power plants, power units for recovered energy-based power generation and remote power units and other generators, we, from time to time, enter into sales agreements 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, ASME and TÜV, and we are an approved supplier to many electric utilities around the world.

Backlog

The Company and its wholly owned subsidiaries have a products backlog of $89.5 million as of February 28, 2007, which includes revenues for the period between January 1, 2007 and February 28, 2007, compared to $81.8 million as of March 15, 2006. The following is a breakdown of the Products Segment backlog:

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Products backlog

	Expected Completion of Contract	Sales Expected to be Recognized in 2007 (in millions)	Sales Expected to be Recognized in the Years Following 2007 (in millions)
North America			
Raft River	2007	$ 16.2	$ —
Blundell	2007	5.0	—
NRGreen, Canada	2007	24.8	—
Enpower Green, Canada	2008	2.4 – 4.9	4.1 – 6.6
Total North America		48.4 – 50.9	4.1 – 6.6
Worldwide (Except North America)			
ICQ, Italy	2007	0.5	—
Enagas Almendralejo, Spain	2007	3.1	—
Comita, Russia	2008	—	2.4
Mokai 1A, New Zealand	2007	0.4	—
Landau Geo X GmbH, Germany	2007	3.6	—
Sakhalin, Russia	2007	2.4	—
Bongkot, Thailand	2007	0.4	—
Ngawha II, New Zealand	2008	5.8 – 10.3	10.5 – 15.0
Other Units	2007	0.9	—
Total Worldwide (Except North America)		17.1 – 21.6	12.9 – 17.4
Total Products Backlog		$ 65.5 – 72.5	$ 17.0 – 24.0

We expect that our revenues from electricity for the 2007 fiscal year will be approximately $220 million from our wholly owned projects and approximately $18.0 million from our subsidiaries accounted for by the equity method.

Our Technology

Our proprietary technology covers power plants operating according to the Organic Rankine Cycle only or in combination with the Steam Rankine Cycle and Brayton Cycle, as well as integration of power plants with 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 our motive fluids are non-ozone-depleting substances. Using advanced computerized fluid dynamics and other computer aided design, or CAD, 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. In particular, we are examining ways to increase the output of our plants by utilizing evaporative cooling, cold reinjection, performance simulation programs, and topping turbines. In the geothermal as well as the recovered energy (waste heat) area, we are examining two-level recovered energy systems and new motive fluids.

We also construct combined cycle geothermal 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.

In the conversion of geothermal energy into electricity, our technology has a number of advantages compared with conventional geothermal steam turbine plants. A conventional geothermal steam turbine plant consumes significant quantities of water, causing depletion of the aquifer, and also requires cooling water treatment with chemicals and thus a need for the disposition 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 tower during cold weather. By contrast, our binary and combined cycle geothermal power plants have a low profile with minimum visual impact and do not emit a

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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. Accidental or fugitive emissions (that result from minor leaks) of motive fluids are within the limits defined by federal, state and local regulatory standards.

Other advantages of our technology include simplicity of operation and easy maintenance, low RPM, temperature and pressure in the Ormat Energy Converter, a high efficiency turbine and the fact that there is no contact between the turbine itself and often corrosive geothermal fluids.

We use the same elements of our technology in our recovered energy products. The heat source could be exhaust gases from a simple cycle gas turbine, low pressure steam or medium temperature liquid found in the process industry. In most cases, we attach an additional heat exchanger in which we circulate thermal oil to transfer the heat into the Ormat Energy Converter'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 the Ormat Energy Converter used in our geothermal power plants. The same advantages of using the Organic Rankine Cycle apply here as well. In addition, our technology allows for better load following than a conventional steam turbine can exhibit, requires no water treatment as it is air cooled, and does not require the continuous presence of a steam licensed operator on site.

More than 70 United States patents (and about 10 pending patents) cover our products (mainly power units based on the Organic Rankine Cycle) and systems (mainly geothermal power plants and industrial waste heat recovery for electricity production). The systems-related patents cover not only a particular component but rather the overall effectiveness of the plant's systems from the ''fuel'' (i.e., geothermal fluid, waste heat, biomass or solar) to generated electricity. The duration of such patents ranges from one year to 14 years. No single patent on its own is material to our business.

The products-related patents cover components such as turbines, heat exchanges, seals and controls. The system patents cover subjects such as disposal of non-condensable gases present in geothermal fluids, power plants for very high pressure geothermal resources and use of two-phase fluids. A number of patents cover the 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.

We are also involved in developing new technology to extract heat from the earth by circulating fluid through an enhanced or man-made reservoir created in naturally low permeable or water-poor rocks. We are undertaking this development in cooperation with GeothermEx Inc., the University of Utah, Energy & Geoscience Institute, the University of Nevada-Reno and the Great Basin Center for Geothermal Energy, with funding support from the United States Department of Energy.

Competition

The power generation industry is characterized by intense competition from electric utilities, other power producers, and marketers. In recent years, the United States in particular has seen increasing competition in power sales, in part due to excess capacity in a number of U.S. markets and an emphasis on short-term markets. In the last year, competition from the wind and solar power generation industry has increased. While the current demand for renewable energy is large enough that this increased competition has not impacted our ability to obtain new power purchase agreements, this increased competition may contribute to a reduction in electricity prices for new renewable projects.

In the geothermal power generation sector, our main competitors in the United States are CalEnergy, Calpine (which filed for protection under Chapter 11 of the U.S. Bankruptcy Code in late 2005), Caithness and other smaller-sized developers such as U.S. Geothermal. Some of these companies are also active outside of the United States. Outside of the United States, aside from these companies and ENEL, which is based in Italy, we may face competition from national electric utilities or state-owned oil companies.

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In the products business, our main competitors are Mitsubishi, Fuji and Toshiba of Japan, GE/Nuevo Pignone, Ansaldo and Turboden of Italy, Siemens of Germany, Alstom of France and Kaluga of Russia. Recently, two new small players have been trying to penetrate the market. In the remote power unit business, we face competition from Global Thermoelectric, as well as from manufacturers of diesel generator sets. Recently, United Technologies announced the introduction of a small 200 kW Organic Rankine Cycle unit.

Siemens of Germany as well as other manufacturers of conventional steam turbines are potential competitors in the recovered energy generation business; although we believe that our recovered energy generation system has technological and economical advantages over the Siemens/Kalina technology and, under certain conditions, conventional steam technology.

We also compete with companies engaged in the power generation business from renewable energy sources other than geothermal energy, such as wind power, solar power and hydro-electric power.

None of our competitors competes with us both in the sale of electricity and in the products business.

Customers

Most of our revenues from the sale of electricity in the year ended December 31, 2006 were derived from fully-contracted energy and/or capacity payments under long-term power purchase agreements with governmental and private utility companies. Southern California Edison, Hawaii Electric Light Company and Sierra Pacific Power Company accounted for 30.0%, 15.1% and 12.8% of revenues, respectively, for the year ended December 31, 2006. Based on publicly available information, as of December 31, 2006, the issuer ratings of Southern California Edison, Sierra Pacific Power Company and Nevada Power Company (a power purchaser for the Desert Peak 2 and Galena 2 projects) were A3 (stable outlook), Ba3 (stable outlook) and Ba3 (stable outlook), respectively, from Moody's Investors Services and BBB+ (stable outlook), BB− (stable outlook), and BB− (stable outlook), respectively, from Standard & Poor's Ratings Services and the issuer rating of Hawaii Electric Light Company was BBB+ (negative outlook) from Standard & Poor's Ratings Services. SCPPA, which has purchased the power from the Gould project since the beginning of 2006, has senior unsecured debt ratings ranging from A1 from Moody's and A+ from S&P, in each case with a stable ratings outlook. The credit ratings of any power purchaser may decrease from time to time. There is no publicly available information with respect to the credit rating or stability of the power purchasers under the power purchase agreements for our foreign power projects.

Our revenues from the products business were derived from contractors or 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 such raw materials are readily available from various suppliers.

Since 2005 we have increased the volume of work ordered from subcontractors for some of the manufacturing for our products components and for construction activities of our power plants, which allowed 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 of our projects ourselves without adverse effect to our operations.

Employees

As of December 31, 2006, we employed 774 employees, of which 252 were located in the United States, 363 were located in Israel and 159 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.

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None of our employees (other than the Momotombo project employees) are represented by a labor union, and 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.

We have no collective bargaining agreements with respect to our Israeli employees. However, by order of the Israeli Ministry of Industry, Trade and Labor 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 non-managerial, finance and administrative, and sales and marketing personnel. This collective bargaining agreement principally concerns cost of living increases, length of the workday, minimum wages, insurance for work-related accidents, procedures for dismissing employees, annual and other vacation, sick pay, 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 and earthquake coverage, and primary and excess liability insurance, as well as customary worker's compensation and automobile insurance and such other insurance, if any, as is generally carried by companies engaged in similar businesses and owning similar properties in the same general areas and financed in a similar manner. To the extent any such casualty insurance covers both us and/or our projects, on the one hand, and any other person and/or plants, on the other hand, we generally have specifically designated as applicable solely to us and our projects ''all risk'' property insurance coverage in an amount based upon the estimated full replacement value of our projects (provided that earthquake and flood coverage may be subject to annual aggregate limits depending on the type and location of the project) and business interruption insurance in an amount that also varies from project to project.

We generally purchase insurance policies to cover our exposure to certain political risks involved in operating in developing countries. Political risk insurance policies are generally issued by entities which specialize in such policies, such as the Multilateral Investment Guarantee Agency (a member of the World Bank Group), and from private sector providers, such as Zurich Re, AIG and other such companies. To date all of our political risk insurance contracts are with the Multilateral Investment Guarantee Agency and with Zurich Re. Such insurance policies cover, in general, and subject to the limitations and restrictions contained therein, 80% to 90% of our revenue loss derived from a specified governmental act, such as confiscation, expropriation, riots, the inability to convert local currency into hard currency and, in certain cases, the breach of agreements. We have obtained such insurance for all of our foreign projects in operation except for the Leyte project.

Regulation of the Electric Utility Industry in the United States

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

PURPA

PURPA provides certain benefits described below, if a project is a ''Qualifying Facility''. There are two types of Qualifying Facilities: cogeneration facilities and small power production facilities. A small power production facility is a Qualifying Facility if (i) the facility does not exceed 80 megawatts, (ii) the primary energy source of the facility is biomass, waste, renewable resources, or any combination thereof, and 75% of the total energy input of the facility is from these sources; and (iii) the facility has filed with FERC a notice of self-certification of qualifying status, or has filed with FERC an application for FERC certification of qualifying status, that has been granted. The 80 megawatt 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, or waste resources; and (ii) an application for

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certification or a notice of self-certification of qualifying status of the facility was submitted to the FERC prior to December 21, 1994, and construction of the facility commenced prior to December 31, 1999.

PURPA exempted Qualifying Facilities from regulation under the Public Utility Holding Company Act of 1935 (PUHCA) and exempts Qualifying Facilities from most provisions of the Federal Power Act (FPA) and state laws relating to the financial, organization and rate regulation of electric utilities. In addition, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by Qualifying Facilities at a rate based on the purchasing utility's incremental cost of purchasing or producing energy (also known as ''avoided cost'').

Pursuant to the Energy Policy Act of 2005, FERC has recently issued a final rule that will require Qualifying Facilities to obtain market-based rate authority pursuant to the FPA for sales of energy or capacity (i) from facilities larger than 20 MW in size; (ii) pursuant to a contract executed after March 17, 2006 that is not a contract made pursuant to a state regulatory authority's implementation of PURPA; or (iii) not pursuant to another provision of a state regulatory authority's implementation of PURPA. The practical effect of this final rule is to require Qualifying Facilities that are larger than 20 MW in size that seek to engage in non-PURPA sales of power (i.e. power that is sold in a manner that is not pursuant to a pre-existing contract or state implementation of PURPA) to obtain market-based rate authority from FERC for these non-PURPA sales.

The Energy Policy Act of 2005 also allows FERC to terminate a utility's obligation to purchase energy from Qualifying Facilities upon a finding that Qualifying Facilities have nondiscriminatory access to either (i) independently administered, auction-based day ahead and real time markets for energy and wholesale markets for long-term sales of capacity; (ii) transmission and interconnection services provided by a FERC-approved regional transmission entity and administered under an open-access transmission tariff that affords nondiscriminatory treatment to all customers, and competitive wholesale markets that provide a meaningful opportunity to sell capacity and energy, including long and short term sales; or (iii) wholesale markets for the sale of capacity and energy that are at a minimum of comparable competitive quality as markets described in (i) and (ii) above. FERC has recently issued a rule to implement these provisions of the Energy Policy Act of 2005. This rule gives nine (9) utilities the right to apply to eliminate the mandatory purchase obligation if the utility is a member of one of four regional transmission organizations. None of our domestic projects sells power pursuant to contracts with utilities in any of these four regional transmission organizations. The rule also creates a rebuttable presumption that a utility provides nondiscriminatory access if it has an open access transmission tariff in compliance with FERC's pro forma open access transmission tariff, which is currently under review by FERC to ensure that its provisions prevent undue discrimination in the provision of transmission service. Further, the rule provides a procedure for utilities that are not members of the four named regional transmission organizations to file to obtain relief from the mandatory purchase obligation on a service territory-wide basis, and establishes procedures for affected Qualifying Facilities to seek reinstatement of the purchase obligation. The rule protects a Qualifying Facility's rights under any contract or obligation involving purchases or sales that are entered into after August 8, 2005 but before FERC has determined that the contracting utility is entitled to relief from the mandatory purchase obligation. The rule also protects a Qualifying Facility's rights under any contract or obligation for the sale of energy in effect or pending approval before the appropriate state regulatory authority or non-regulated electric utility on August 8, 2005.

In addition, the Energy Policy Act of 2005 eliminated the restriction on utility ownership of a Qualifying Facility. Prior to the Energy Policy Act of 2005, electric utilities or electric utility holding companies could not own more than a 50% equity interest in a Qualifying Facility. Under the Energy Policy Act of 2005, electric utilities or holding companies may own up to 100% of the equity interest in a Qualifying Facility.

We expect that our projects will continue to meet all of the criteria required for Qualifying Facilities under PURPA. However, since the Heber Projects have power purchase agreements 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 Projects loses its Qualifying

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Facility status our operations could be adversely affected. Loss of Qualifying Facility status would eliminate the Heber Project's exemption from the FPA and thus, among other things, the rates charged by the Heber Projects in the power purchase agreements with Southern California Edison and SCPPA would become subject to FERC regulation. Further, it is possible that the utilities that purchase power from the projects could successfully obtain an elimination of the mandatory-purchase obligation in their service territories. If this occurs, the Project's existing power purchase agreements will not be affected, but the utilities will not be obligated under PURPA to renew these power purchase agreements or execute new power purchase agreements upon the existing power purchase agreements' expiration.

PUHCA

PUHCA has been repealed, effective February 8, 2006, pursuant to the Energy Policy Act of 2005. Although PUHCA was repealed, the Energy Policy Act of 2005 created a new Public Utility Holding Company Act of 2005 (PUHCA 2005). 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. 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. By virtue of being Qualifying Facilities that make only wholesale sales of electricity, Qualifying Facilities already are not subject to state commissions' rate, financial and organizational 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 state regulation.

FPA

Pursuant to the FPA, the FERC has exclusive rate-making jurisdiction over 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. Qualifying Facilities are generally exempt from the FPA. If any of the projects were to lose its Qualifying Facility status, such project could also become subject to the full scope of the FPA and applicable state regulations. The application of the FPA and other applicable state regulations to the projects could require our operations to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility. Even if a project does not lose Qualifying Facility status, pursuant to a final rule issued by FERC pursuant to the Energy Policy Act of 2005, if a power purchase agreement with a project is terminated or otherwise expires, the project will become subject to rate regulation under the Federal Power Act.

If a project was to become subject to FERC's ratemaking jurisdiction under the FPA as a result of loss of Qualifying Facility status and the power purchase agreement remains in effect, the FERC may determine that the rates currently set forth in the power purchase agreement are not appropriate and may set rates that are lower than the rates currently charged. In addition, the FERC may require that the project refund amounts previously paid by the relevant power purchaser to such project. Such events would likely result in a decrease in our future revenues or in an obligation to

disgorge revenues previously received from the project, either of which would have an adverse effect on our revenues.

Moreover, the loss of the Qualifying Facility status of any of our projects selling energy to Southern California Edison could also permit Southern California Edison, pursuant to the terms of its power purchase agreement, to cease taking and paying for electricity from the relevant project and to seek refunds for past amounts paid. In addition, the loss of any such status would result in the occurrence of an event of default under the indenture for the bonds and hence would give rise to the ability of the indenture trustee to exercise remedies pursuant to the indenture and the other financing documents.

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State Regulation

Our projects in California and Nevada, by virtue of being Qualifying Facilities that make only wholesale sales of electricity, are not subject to rate, financial and organizational regulations applicable to electric utilities in those states. The projects each sell or will sell their electrical output under power purchase agreements to electric utilities (Sierra Pacific Power Company, Nevada Power Company, Southern California Edison or Southern California Public Power Authority). All of the utilities except Southern California Public Power Authority are regulated by their respective state public utility commissions. Sierra Pacific Power Company and Nevada Power Company are regulated by the Public Utility Commission of Nevada. Southern California Edison and a small portion of Sierra Pacific Power Company in the Lake Tahoe area are regulated by the California Public Utility Commission.

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 Hawaii Public Utility Commission 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 cost it would otherwise incur if it produced the energy and capacity itself or purchased it from another source. Our project in Hawaii has a long term power purchase agreement with Hawaii Electric Light Company.

Foreign Regulation of the Electric Utility Industry

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 project and should not be considered a full statement of the laws in such countries or all of the issues pertaining thereto.

Nicaragua. In 1998 two laws were approved by Nicaraguan authorities, Law No. 272-98 and Law No. 271-98, which define the structure of the new energy sector in the country. Law No. 272-98 provides for the establishment of a National Energy Commission, which we refer to as CNE, which is responsible for setting policies, strategies and objectives for such sector and approving indicative plans therefor. Law No. 271-98 formally assigned regulatory, supervisory, inspection and oversight functions to the Nicaraguan Institute of Energy, which we refer to as INE.

In 2002, the National Congress enacted Law No. 443 to regulate the granting of exploration and exploitation concessions for geothermal fields. The INE adopted this law.

In 2007, Nicaragua passed a law amending Law No. 290, which governs the organization of the executive branch. Among other matters, the new law established a new ministry of energy and mining, which has assumed all of the functions and responsabilities of the National Energy Commission (CNE). The new ministry of energy and mining is responsible for administrating Law No. 443 described above, and is also responsible for granting concessions and permits relating to the exploration or exploitation of any energy source, as well as concessions and licensing for generation, transmission and distribution of energy.

The Nicaraguan energy sector has been restructured and partially privatized. Following such restructuring and privatization, the government has retained title and control of the transmission assets and has created the Empresa Estatal de Transmision (ENTRESA), which is in charge of the operation of the transmission system in the country and of the new wholesale market. As part of the recent restructuring of the energy sector, most of the distribution facilities previously owned by the Nicaraguan Electricity Company, the government-owned vertically-integrated monopoly, were transferred to two companies, Empresa Distribuidora de Electricidad del Norte (DISNORTE) and Empresa Distribuidora de Electricidad del Sur (DISSUR), which in turn were privatized and acquired by an affiliate of Union Fenosa, a large Spanish utility. Following such privatization, the power purchase agreement for our Momotombo project was assigned by the Nicaraguan Electricity Company to DISNORTE and DISSUR. A subsidiary of the Nicaraguan Electricity Company, ENTRESA, owns the transmission grid. In addition, a National Dispatch Center was created to work with ENTRESA and provide for dispatch and wholesale market administration.

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Guatemala. The General Electricity Law of 1996 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 National Electric Energy Commission (CNEE) and a new wholesale power market administrator, the Administrator of the Wholesale Market, for the regulation and administration of such sector. The CNEE functions as an independent agency under the Ministry of Energy and Mines and is in charge of regulating the electricity law, overseeing the market and setting rates for transmission services and for electricity service 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 Projects in order to promote the development of renewable energy projects in Guatemala. Such law provides certain benefits to companies utilizing renewable energy, including a 10-year corporate income tax; VAT and customs duty exemption and a 10-year business tax exemption.

Kenya. Kenya's Electric Power Act of 1997 restructured the electricity sector in such country. Among other things, the Act provides for the licensing of electricity power producers and public electricity suppliers or distributors. Kenya Power and Lighting Co. Ltd. (KPLC) is the only licensed public electricity supplier and has a monopoly in the transmission and distribution of electricity in the country. The Act permitted Independent Power Producers (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 two other IPPs in addition to our Olkaria III project. The Act also created the Electricity Regulation Board, as an independent regulator for the electricity sector. KPLC.'s retail electricity rates are subject to approval by the Electricity Regulation Board.

Philippines. The Philippine's Electric Power Industry Reform Act of 2001 created the Energy Regulatory Commission, which is an independent quasi-judicial regulatory body mandated to promote competition, encourage market development, ensure customer choice and penalize abuse of market power in the restructured electricity

industry. The Energy Regulatory Commission is responsible for the enforcement of the rules and regulations governing the operations of the electricity spot market once it is established and the activities of the spot market operator and other participants to ensure a greater supply and rational pricing of electricity. In addition, the Energy Regulatory Commission determines, fixes, and approves transmission and distribution wheeling charges and retail electricity rates for the captive market of a distribution utility through a methodology that it establishes and enforces. The Energy Regulatory Commission also monitors and takes measures to penalize abuse of market power and anti-competitive or discriminatory behavior by any electric power industry participant.

Permit Status

While our power generation operations produce electricity without emissions of certain pollutants such as nitrogen oxide, and with far lower emissions of other pollutants such as carbon dioxide, some of our projects do emit air pollutants in quantities that are subject to regulation under applicable environmental air pollution laws. Such operations typically require air permits. Especially critical to our geothermal operations are those permits and standards applicable to the construction and operation of geothermal wells and brine reinjection wells. In the United States, injection wells are regulated under the federal Safe Drinking Water Act Underground Injection Control, which we refer to as UIC, program. Our injection wells typically fall into UIC Class V, one of the least regulated categories, because fluids are reinjected to enhance utilization of the geothermal resource. Our projects 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 their operation. Some of the environmental permits and governmental approvals that have been issued to the projects contain conditions and restrictions, including restrictions or limits on emissions and discharges of pollutants and contaminants, or may have limited terms.

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Our operations are designed and conducted to comply with applicable permit requirements. Non-compliance with any such requirements could result in fines or other penalties. We are not aware of any non-compliance with such requirements that would be likely to result in material fines or penalties; however, the Heber 1 and 2 projects received a notice from the California Division of Oil, Gas and Geothermal Resources that the pressure levels at some of the geothermal fluid injection wells were too high, and the California Regional Water Quality Control Board has notified the Heber 1 and 2 projects that recent tests have resulted in lower-than-required survival rates for bioassay toxicity tests conducted on the cooling tower blowdown water discharged under the NPDES (National Pollutant Discharge Elimination System) permit. In order to address the pressure levels at the Heber 1 and 2 projects, the Heber 1 and 2 projects proposed the construction and operation of a pipeline to carry geothermal injection fluid to other project injection wells, which proposal has been accepted as an appropriate solution to the pressure level by the California Division of Oil, Gas and Geothermal Resources. The pipeline was completed in the first quarter of 2005. With the cooperation of the California Regional Water Quality Control Board, Colorado River Basin Region, the Heber 1 and 2 projects are also conducting more frequent monitoring and bioassays, and conducting a Toxicity Identification Evaluation (TIE) study in an effort to determine the source of the apparent cooling tower blowdown water toxicity. If the source of the toxicity is not identified, or cannot easily be corrected, the Heber 1 and 2 projects may instead seek authority to inject the cooling tower blowdown water into the geothermal injection reservoir, as do other geothermal projects in the Imperial Valley.

Our Steamboat Hills Project was recently advised by the Washoe County Water Department that certain changes had been observed in the course of the County’s monitoring of well chemistry and was asked to explain why this was

occurring. In the course of our investigation, we discovered that a liner in a geothermal fluid injection well failed, resulting in injection of the spent geothermal fluid at a higher depth than the designed and permitted depth for such injection. The County Water Department and the State have also indicated their concern that the injection well may be situated near a geological fault, which may also be causing the movement of injected fluid into a higher zone of the groundwater aquifer. We engaged an outside geothermal consultant to examine the situation and have since completed the well repair work. We do not believe that the injection well has had a material impact on the aquifer or that it is improperly placed. We have agreed with the State to conduct an expanded monitoring program and to continue to study the issue. If it should be determined that the injection well location is not acceptable, it may be necessary to drill a new injection well to manage the spent geothermal fluids.

As of the date of this annual report, all of the material permits and approvals currently required to operate our projects have been obtained and are currently valid, except for the fact that certain permits for some of the projects are held in the name of predecessor owners and except for those permits which must be transferred or reissued to the correct entity. We believe this will occur in the ordinary course and we have already filed some of these applications. In addition, we are required to obtain permits for both the construction and operational phases of our projects under construction or enhancement. As of the date of this annual report, we have obtained and are in compliance with most of the material permits and approvals currently required for our projects that are under construction or enhancement. There are some permits that need to be obtained in the future. We believe we will be able to obtain those permits and approvals without material delay and without incurring additional material costs.

Environmental Laws and Regulations

Geothermal operations can produce significant quantities of brine and scale, which builds up on metal surfaces in our equipment with which the brine comes into contact. These waste materials, most of which are currently reinjected into the subsurface, can contain various concentrations of hazardous materials, including arsenic, lead, and naturally occurring radioactive materials. We also use various substances, including isobutene, isopentane, and industrial lubricants, that could become potential contaminants and are generally flammable. Hazardous materials are also used and generated in connection with our equipment manufacturing operations in Israel. As a result, our projects are

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subject to numerous domestic and foreign federal, state and local statutory and regulatory standards relating to the use, storage, fugitive emissions and disposal of hazardous substances. The cost of any remediation activities in connection with a spill or other release of such contaminants 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 projects, that has materially impaired any of the project sites, any disposal or release of these materials onto project sites, other than by means of permitted injection wells, could result in material cleanup requirements or other responsive obligations under applicable environmental laws. We believe that at one time there may have been a gas station located on the Mammoth project site (which we lease), but because of significant surface disturbance and construction since that time further physical evaluation of the former gas station site has been impractical. We believe that, given the subsequent surface disturbance and construction activity in the vicinity of the suspected location of the service station, it is likely that the former facilities and any associated underground storage tanks would have already been encountered if they still existed.

ITEM 1A. RISK FACTORS

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

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

Our financial performance depends on the successful operation of our subsidiaries' geothermal power plants. In connection with such operations, we derived approximately 72.7% of our total revenues for the year ended December 31, 2006 from the sale of electricity. The cost of operation and maintenance and the operating performance of our subsidiaries' geothermal power plants may be adversely affected by a variety of factors, including some that are discussed elsewhere in these risk factors and the following:

- regular and unexpected maintenance and replacement expenditures;
- shutdowns due to the breakdown or failure of our equipment or the equipment of the transmission serving utility;
- labor disputes;
- the presence of hazardous materials on our project sites;
- catastrophic events such as fires, explosions, earthquakes, landslides, floods, releases of hazardous materials, severe storms or similar occurrences affecting our projects or any of the power purchasers or other third parties providing services to our projects; and
- the aging of power plants may reduce their availability and increase the cost of their maintenance.

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

As mentioned above, the aging of our power plants may reduce their availability and increase maintenance costs due to the need to repair or replace our equipment. For example, in 2006, we had to retube old heat exchanger pipes in our Mammoth complex. Such major maintenance activities impact both the capacity factor of the affected power plant and its operating costs.

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

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Our business involves the exploration, development and operation of geothermal energy resources. These activities are subject to uncertainties, which vary among different geothermal reservoirs and are in some respects similar to those typically associated with oil and gas exploration, development and exploitation, such as dry holes, uncontrolled releases and pressure and temperature decline, all of which can increase our operating costs and capital expenditures or reduce the efficiency of our power plants. Prior to our acquisition of the Steamboat Hills project, one of the wells related to the project experienced an uncontrolled release. In addition, the high temperature and high pressure in the Puna project's geothermal energy resource requires special reservoir management and monitoring. Further, since the

commencement of their operations, several of our projects have experienced geothermal resource cooling 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 projects depends on different factors directly related to the geothermal resource, such as the heat content (the relevant composition of temperature and pressure) of the geothermal reservoir, the useful life (commercially exploitable life) of the reservoir and operational factors relating to the extraction of geothermal fluids. Our geothermal energy projects may 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. In addition, we may fail to find commercially viable geothermal resources in the expected quantities and temperatures, which would adversely affect our development of geothermal power projects.

Another aspect of geothermal operations is the management and stabilization of subsurface impacts caused by fluid injection pressures. In the case of the geothermal resource supplying the Heber 1 project and the Heber 2 project, which we refer to collectively as the ‘‘Heber projects’’, and the Gould project (a new power plant at the site of the Heber projects consisting of two Ormat Integrated Two Level Units (ITLU)), pressure drawdown in the center of the well field has caused some localized ground subsidence, while pressure in the peripheral areas has caused localized ground inflation. Inflation and subsidence, if not controlled, can adversely affect farming operations and other infrastructure at or near the land surface. Potential costs, which cannot be estimated and may be significant, of failing to stabilize site pressures in the Heber and Gould projects’ area include repair and modification of gravity-based farm irrigation systems and municipal sewer piping and possible repair or replacement of a local road bridge spanning an irrigation canal.

Additionally, geothermally active areas, such as the areas in which our projects are located, are subject to frequent low-level seismic disturbances. Serious seismic disturbances are possible and could result in damage to our projects or equipment or degrade the quality of our geothermal resources to such an extent that we could not perform under the power purchase agreement for the affected project, 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, 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.

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

We are currently in the process of developing and constructing a number of new power plants. Our success in developing a particular project is contingent upon, among other things, negotiation of satisfactory engineering and construction agreements and power purchase agreements, receipt of required governmental permits, obtaining adequate financing, and the timely implementation and satisfactory completion of construction. 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 power purchase agreement, obtaining all required governmental permits and approvals and arranging 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 power plants under development or construction in the United States, Kenya, and China, 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:

- unanticipated cost increases;
- shortages and inconsistent qualities of equipment, material and labor;
- work stoppages;
- inability to obtain permits and other regulatory matters;
- failure by key contractors and vendors to timely and properly perform;
- adverse environmental and geological conditions (including inclement weather conditions); and
- our attention to other projects;

Any one of which 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 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.

Our geothermal power plants generally have been financed using leveraged financing structures, consisting of non-recourse or limited recourse debt obligations. As of December 31, 2006, we had approximately $512.2 million of total consolidated indebtedness (including indebtedness to our parent company in the amount of $140.2 million), of which approximately $370.0 million represented non-recourse debt and limited recourse debt held by our subsidiaries. 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 with 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 and capital market conditions, credit availability from banks, investor confidence, the continued success of current projects, the credit quality of the projects being financed, the political situation in the country where the project 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 projects on a substantially non-recourse or limited recourse basis, we may have to finance them using recourse capital such as direct equity investments, parent company loans 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.

Our foreign projects expose us to risks related to the application of foreign laws, taxes, economic conditions, labor supply and relations, political conditions and policies of foreign governments, any of which risks may delay or reduce our ability to profit from such projects.

We have substantial operations outside of the United States that generated revenues in the amount of $95.4 million for the year ended December 31, 2006, which represented 35.5% of our total revenues for such twelve-month period. Our foreign operations are subject to regulation by various foreign governments and regulatory authorities and are subject to the application of foreign laws. Such foreign laws or regulations may not provide for the same type of legal certainty and rights, in connection with our contractual relationships in such countries, as are afforded to our projects

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United States, which may adversely affect our ability to receive revenues or enforce our rights in connection with our foreign operations. Furthermore, existing laws or regulations may be amended or repealed, and new laws or regulations may be enacted or issued. In addition, the laws and regulations of some countries may limit our ability to hold a majority interest in some of the projects that we may develop or acquire, thus limiting our ability to control the development, construction and operation of such projects. Our foreign operations are also subject to significant political, economic and financial risks, which vary by country, and include:

- changes in government policies or personnel;
- changes in general economic conditions;
- restrictions on currency transfer or convertibility;
- changes in labor relations;
- political instability and civil unrest;
- changes in the local electricity market;
- breach or repudiation of important contractual undertakings by governmental entities; and
- expropriation and confiscation of assets and facilities.

In particular, the Philippines is in the midst of an ongoing privatization of the electric industry, and 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 existing Leyte and Zunil projects and the Amatitlan project (Leyte in the Philippines and Zunil and Amatitlan in Guatemala) currently under construction if, for example, they result in changes to the prevailing tariff regime or in the identity and creditworthiness of our power purchasers. In Nicaragua, Union Fenosa, one of the electric utilities, has been experiencing difficulties adjusting the tariffs charged to its customers, thus effecting Union Fenosa's ability to pay for electricity its purchase from power generators. This may adversely affect our Momotombo project. In Kenya, the government is continuing to make an effort to deliver on campaign promises to reduce the price of electricity and is applying pressure on independent power producers, to lower their tariffs. In addition, Kenya's government is considering a further restructuring and privatization of the electricity industry and may divide Kenya Power and Lighting Co. Ltd., the power purchaser for our Olkaria III project, into separate entities and then privatize one or more of such resulting entities. Any break-up and potential privatization of Kenya Power and Lighting Co. Ltd. may adversely affect our Olkaria III project. Although we generally obtain political risk insurance in connection with our foreign projects, 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 project 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.

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

Risks attributable to fluctuations in currency exchange rates can arise when any of our foreign subsidiaries borrow funds or incur operating or other expenses in one type of currency but receive revenues in another. In such cases, an adverse change in exchange rates can reduce such subsidiary's ability to meet its debt service obligations, reduce the amount of cash and income we receive from such foreign subsidiary or increase such subsidiary's overall expenses. In

addition, the imposition by foreign governments of restrictions on the transfer of foreign currency abroad, or restrictions on the conversion of local currency into foreign currency, would have an adverse effect on the operations of our foreign projects and foreign manufacturing operations, and may limit or diminish the amount of cash and income that we receive from such foreign projects and operations.

A significant portion of our net revenue is attributed to payments made by power purchasers under power purchase agreements. The failure of any such power purchaser to perform its obligations under

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the relevant power purchase agreement or the loss of a power purchase agreement 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 net revenue is attributed to revenues derived from power purchasers under the relevant power purchase agreements. Southern California Edison, Hawaii Electric Light Company and Sierra Pacific Power Company have accounted for 30.0%, 15.1% and 12.8%, respectively, of our revenues for the year ended December 31, 2006. Neither we nor any of our affiliates make any representations as to the financial condition or creditworthiness of any purchaser under a power purchase agreement, and nothing in this annual report should be construed as such a representation.

There is a risk that any one or more of the power purchasers may not fulfill their respective payment obligations under their power purchase agreements. For example, as a result of the energy crisis in California, Southern California Edison withheld payments it owed under various of its power purchase agreements with a number of power generators (such as the Ormesa, Heber, and Mammoth projects) payable for certain energy delivered between November 2000 and March 2001 under such power purchase agreements until March 2002. If any of the power purchasers fails to meet its payment obligations under its power purchase agreements, it could materially and adversely affect our business, financial condition, future results and cash flow.

In connection with the power purchase agreements for the Ormesa project, Southern California Edison has expressed its intent not to pay the contract rate for the power supplied by the GEM 2 and GEM 3 plants to the Ormesa project. Southern California Edison contends that California ISO real-time prices should apply, while management believes that SP-15 prices quoted by NYMEX should apply. According to Southern California Edison’s estimation, the amount under dispute is approximately $2.5 million. The parties have signed an Interim Agreement; whereby Southern California Edison will continue procure the GEM 2 and GEM 3 power at the current energy rate of 5.37 cents/ kWh until May 1, 2007. In addition, a long-term power purchase agreement is expected to be entered into for the GEM 2 and GEM 3 power. The negotiations of the long-term power purchase agreement are still under way and there is no guarantee that it will be successfully completed.

Seasonal variations may cause significant 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 domestic projects receive higher capacity payments under the relevant power purchase agreements during the summer months, and due to the generally higher short run avoided costs in effect during the summer months. Some of our other projects 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.

Pursuant to the terms of some of our power purchase agreements with investor-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.

Under the Burdette, Desert Peak 2, Galena 2, Galena 3, Carson Lake and Buffalo Valley power purchase agreements, we may be required to make payments to the relevant power purchaser in an amount equal to such purchaser's replacement costs for renewable energy relating to any shortfall amount of renewable energy that we do not provide as required under the power purchase agreement and which such power purchaser is forced to obtain from an alternate source. One of the six power purchase agreements was in commercial operation in 2006 and to date the shortfall amount has not been material. Measured against our revenues from the sale of electricity for the year ended December 31, 2006 and assuming no other changes in our revenues, the revenues from such agreements constitute, collectively, less than 4% of our total revenues from the sale of electricity. In addition, we may be required to make payments to the relevant power purchaser in an amount equal

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to its replacement costs relating to any renewable energy credits we do not provide as required under the relevant power purchase agreement. We may be subject to certain penalties, and we may also be required to pay liquidated damages if certain minimum performance requirements are not met under certain of our power purchase agreements, all of which could materially and adversely affect our business, financial condition, future results and cash flow. With respect to certain of our power purchase agreements, we may also be required to pay liquidated damages to our power purchaser if the relevant project does not maintain availability of at least 85% during applicable peak periods. The maximum aggregate amount of such liquidated damages for the Steamboat 2 and Steamboat 3 power purchase agreements would be approximately $1.5 million for each project.

The short run avoided costs for our power purchasers may decline, which would reduce our project revenues and could materially and adversely affect our business, financial condition, future results and cash flow.

Under the power purchase agreements for our projects in California, the price that Southern California Edison pays for energy is based upon its short run avoided costs, which are the incremental costs that it would have incurred had it generated the relevant electrical energy itself or purchased such energy 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 has been fixed through April 2007 and, recently, has been fixed again through April 2012, and thereafter will be based on Southern California Edison's short run avoided costs, as determined by the California Public Utilities Commission. These short run avoided costs 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 short run avoided cost prices paid by Southern California Edison may decline following the expiration date of the settlement agreements, which in turn would reduce our project revenues derived from Southern California Edison under our power purchase agreements and could materially and adversely affect our business, financial condition, future results and cash flow.

If any of our domestic projects 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 projects are Qualifying Facilities pursuant to the Public Utility Regulatory Policies Act of 1978, as amended, which we refer to as PURPA, which largely exempts the projects from the Federal Power Act, which we refer to as FPA, and certain state and local laws and regulations regarding rates and financial and organizational requirements for electric utilities.

PUHCA was repealed on February 8, 2006. If any of our domestic projects were to lose its Qualifying Facility status, such project 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 projects could require our operations to comply with an increasingly complex regulatory regime that may be costly and greatly reduce our operational flexibility.

In addition, pursuant to the FPA, the FERC has exclusive rate-making jurisdiction over wholesale sales of electricity and transmission of public utilities 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. Qualifying Facilities are largely exempt from the FPA. If a domestic project were to lose its Qualifying Facility status, it would become a public utility under the FPA, and the rates charged by such project pursuant to its power purchase agreements would be subject to the review and approval of the FERC. The FERC, upon such review, may determine that the rates currently set forth in such power purchase agreements are not appropriate and may set rates that are lower than the rates currently charged. In addition, the FERC may require that some or all of our domestic projects refund amounts previously paid by the relevant power purchaser to such project. Such events would likely result in a decrease in our future revenues or in an obligation to disgorge revenues previously received from our domestic projects, either of which would have an adverse effect on our revenues. Even if a project does not lose its Qualifying Facility status, pursuant to a final rule

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issued by FERC on February 2, 2006, if a project's power purchase agreement is terminated or otherwise expires, that project 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 power purchase agreement, to cease taking and paying for electricity from the relevant project 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 power purchase agreements, result in significant liability for refunds of past amounts paid, or otherwise impair the value of our projects. 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 project 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 projects, which would enable the lenders to exercise their remedies and enforce the liens on the relevant project.

Pursuant to the Energy Policy Act of 2005, the FERC was also given authority to prospectively lift the mandatory obligation of a utility under PURPA to purchase the electricity from a Qualifying Facility if the utility operates in a workably competitive market. Existing power purchase agreements between a Qualifying Facility and a utility are not affected. The FERC recently issued a final rule, which could eliminate a utility's mandatory purchase obligation from Qualifying Facilities in certain regions of the country. The regions do not include areas in which our domestic projects operate. However, FERC has the authority under the Energy Policy Act of 2005 to act, on a case-by-case basis, to

eliminate the mandatory purchase obligation in other regions. In this rule, the FERC expressly noted that the California Independent System Operator (CAISO) has satisfied one but not all of the criteria for relief from the mandatory purchase obligation. If the utilities in the regions in which our domestic projects operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from the project in the region under Federal law upon termination of the existing power purchase agreement or with respect to new projects, which could have an adverse effect on our revenues.

Our financial performance is significantly dependent on the successful operation of our projects, which is subject to changes in the legal and regulatory environment affecting our projects.

All of our projects 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 projects. The structure of federal and state energy regulation currently is, and may continue to be, subject to challenges, modifications, the imposition of additional regulatory requirements, and restructuring proposals. Our power purchasers or we 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.

The federal government also encourages production of electricity from geothermal resources through certain tax subsidies. We are permitted to claim in our consolidated federal tax returns either an investment tax credit for approximately 10% of the cost of each new geothermal power plant or ‘‘production tax credits’’, which in 2006 was 1.9 cents per kWh and is adjusted annually for inflation, on the first ten years of electricity output. (Production tax credits can only be claimed on new plants put into service between October 23, 2004 and December 31, 2008.) We are also permitted to deduct most of the cost of the power plant as ‘‘depreciation’’ over five years on an accelerated basis. The fact that the deductions are accelerated means that more of the cost is deducted in the first few years than during the remainder of the depreciation period. In addition, we have the ability to transfer the value of these tax incentives when we are not in a position to use them directly. For instance, energy credits can be transferred through lease financing, and production tax credits may be transferred by bringing in another company who can use them as a partner in the project.

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President Bush has made it a central theme of his second term to simplify the U.S. tax code. Among the options that may be under consideration are replacing or supplementing the corporate income tax with a value-added-tax, stripping away many tax subsidies, and eliminating taxes on interest, dividends and other returns to capital. Significant tax reform has the potential to have a material effect on our business, financial condition, future results and cash flow. It could reduce or eliminate the value that geothermal companies receive from the current tax subsidies. Any restrictions or tightening of the rules for lease or partnership transactions — whether or not part of major tax reform — could also materially affect our business, financial condition, future results and cash flow.

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

The costs of compliance with environmental laws and of obtaining and maintaining environmental permits and governmental approvals required for construction and/or operation, which currently are significant, may increase in the future and could materially and adversely affect our business, financial condition, future results and cash flow; any non-compliance with such laws or regulations may result in the imposition of liabilities which could materially and adversely affect our business, financial condition, future results and cash flow.

Our projects 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. Some of the environmental permits and governmental approvals that have been issued to the projects 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 projects could be adversely affected or be subject to fines, penalties or additional costs. In addition, 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 projects. As of the date of this report, we have not yet obtained certain permits and government approvals required for the completion and successful operation of projects under construction or enhancement. In addition, a nearby municipality has informed our Amatitlan project that an additional building permit should be obtained from such municipality before construction commences. Our failure to renew, maintain or obtain required permits or governmental approvals, including the permits and approvals necessary for operating projects under construction or enhancement and the Amatitlan project, could cause our operations to be limited or suspended. 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.

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

Our projects 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 isobutane, isopentane, industrial lubricants and other substances at our projects 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 projects, 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 projects into compliance. Furthermore, in the United States, 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.

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

We may not be able to successfully integrate companies which we 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, the same 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 power purchase agreements 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.

The existence of a prolonged force majeure event or a forced outage affecting a project 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 or other similar events.

If a project experiences an occurrence resulting in a force majeure event, our subsidiary that owns that project would be excused from its obligations under the relevant power purchase agreement. However, the relevant power purchaser may not be required to make any capacity and/or energy payments with respect to the affected project or plant so long as the force majeure event continues and, pursuant to certain of our power purchase agreements, will have the right to prematurely terminate the power purchase agreement. Additionally, to the extent that a forced outage has occurred, the relevant power purchaser may not be required to make any capacity and/or energy payments to the affected project, and if as a result the project fails to attain certain performance requirements under certain of our power purchase agreements, the purchaser may have the right to

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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 power purchase agreement. As a consequence, we may not receive any net revenues from the affected project or 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. Accordingly, our business, financial condition, future results and cash flows could be materially and adversely affected.

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

If the transmission system of the Imperial Irrigation District experiences a force majeure event or a forced outage which prevents it from transmitting the electricity from the Heber 1 and 2 projects or the Ormesa project to the relevant power purchaser, the relevant power purchaser would not be required to make energy payments for such non-delivered electricity and may not be required to make any capacity payments with respect to the affected project so long as such force majeure event or forced outage continues. Our revenues for the year ended December 31, 2006, from the projects utilizing the Imperial Irrigation District transmission system, were approximately $80.7 million. The impact of such force majeure would depend on the duration thereof, with longer outages resulting in greater revenue loss.

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

Most of our geothermal resource leases are for a fixed primary term, and then continue for so long as geothermal resources are extracted in ‘‘commercial quantities’’ or pursuant to other terms of extension. The land covered by some of our leases is undeveloped and has not yet produced geothermal resources in ‘‘commercial quantities’’. Leases that cover land which remains undeveloped and does not produce, or does not continue to produce, geothermal resources in commercial quantities and leases that we allow to expire, will terminate. In the event that a lease is terminated and we determine that we will need that lease once the applicable project 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, all of which may not be possible or could result in increased cost to us, which could materially and adversely affect our business, financial condition, future results and cash flow.

Our Bureau of Land Management leases may be terminated if we fail to comply with any of the provisions of the Geothermal Steam Act of 1970 or if we fail to comply with the terms or stipulations of such leases, which may materially and adversely affect our business and operations.

Pursuant to the terms of our Bureau of Land Management (which we refer to as 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, the payment of royalties for timber and the imposition of certain restrictions on residential development on

the leased land. 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 of 1970 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.

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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 project located on the relevant property and/or terminate our right of access to the underlying geothermal resources required for our operations.

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

Current and future urbanizing activities and related residential, commercial and industrial developments may encroach on or limit geothermal activities in the areas of our projects, 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 projects, thereby affecting our ability to utilize, access, inject and/or transport geothermal resources on or underneath the affected surface areas. In particular, the Heber projects and the Gould project 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 projects and Gould project. 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 Calexio. 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 projects and Gould project, which could adversely affect our operations and reduce our revenues.

Current transportation construction works and urban developments in the vicinity of our Steamboat complex of projects in Nevada may also affect future permitting for geothermal operations relating to those projects. Such works and developments include the extension of an interstate highway (to be named U.S. 580) by the Nevada Department of Transportation, the construction of a new casino hotel and other commercial or industrial developments on land in the vicinity of our Steamboat projects.

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

Our success is largely dependent on the skills, experience and efforts of our senior management team and other key personnel. In particular, our success depends on the continued efforts of Lucien

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Bronicki, Dita Bronicki, Hezy Ram, Nadav Amir, Yoram Bronicki and other key employees. The loss of the services of any key employee could materially harm our business, financial condition, future results and cash flow. Although to date we have been successful in retaining the services of senior management and have entered into employment agreements with Lucien Bronicki, Dita Bronicki, Hezy Ram and Yoram Bronicki, such members of our senior management may terminate their employment agreements without cause and with notice periods ranging from 90 to 180 days. We may also not be able to locate or employ on acceptable terms qualified replacements for our senior management or key employees if their services were no longer available.

Our projects have generally been financed through a combination of parent company loans 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 projects.

Our projects have generally been financed using a combination of parent company loans and limited or non-recourse project finance debt or lease financing. Non-recourse project finance debt or lease financing refers to financing arrangements that are repaid solely from the project's revenues and are secured by the project's physical assets, major contracts, cash accounts and, in many cases, our ownership interest in the project subsidiary. Limited–recourse project finance debt refers to our additional agreement, as part of the financing of a project, to provide limited financial support for the project subsidiary in the form of limited guarantees, indemnities, capital contributions and agreements to pay certain debt service deficiencies. 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 projects, 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 projects) 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 project would only retain an interest in the physical assets, if any, remaining after all debts and obligations were paid in full.

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

A basic premise of our business model is that generating baseload power at geothermal power plants achieves economies of scale and 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, most notably fossil fuel power systems, hydroelectric systems, fuel cells, microturbines, windmills and photovoltaic (solar) cells. Some of these alternative technologies currently produce electricity at a higher average price than our geothermal plants; however, research and development activities are ongoing to seek improvements in such alternate technologies and their cost of producing electricity is gradually declining. It is possible that advances will further reduce the cost of alternate methods of power generation to a level that is equal to or below that of most geothermal power generation technologies. If this were to happen, the competitive advantage of our projects may be significantly impaired.

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

We have identified recovered energy-based power generation as a significant market opportunity for us. Demand for our recovered energy-based power generation units may not materialize or grow at the levels that we expect. We currently face competition in this market from manufacturers of conventional steam turbines and may face competition from other related technologies in the future.

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If this market does not materialize at the levels that we expect, such failure may materially and adversely affect our business, financial condition, future results and cash flow.

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

Our intellectual property rights 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.

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 are subject to risks associated with a changing economic and political environment, which may adversely affect our financial stability or the financial stability of our counterparties.

The risk of terrorist attacks in the United States or elsewhere continues to remain a potential source of disruption to the nation's economy and financial markets in general. The availability and cost of capital for our business and that of our competitors has been adversely affected by the bankruptcy of Enron Corp. and events related to the California electric market crisis. Additionally, the recent rise in fuel costs may make it more expensive for our customers to operate their businesses. These events could constrain the capital available to our industry and could adversely affect our financial stability and the financial stability of our transaction counterparties.

Possible fluctuations in the cost of construction, raw materials 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, and on the supply of various industrial equipment components that we use. We currently obtain all such materials 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. We have recently experienced increases in the cost of raw materials and in transportation costs. We have also experienced an increase in construction costs and an increase in drilling costs. To the extent not otherwise passed along to our customers, these and future cost increases of such raw materials and equipment could adversely affect our profit margins.

Conditions in Israel, where the majority of our senior management and all of our 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 projects.

Operations in Israel accounted for approximately 24.1%, 25.2% and 25.6% of our operating expenses in the year ended December 31, 2006, 2005 and 2004, respectively. Political, economic and security conditions in Israel directly affect our operations. Since the establishment of the State of Israel in 1948, a number of armed conflicts have taken place between Israel and its Arab neighbors, and the continued state of hostility, varying in degree and intensity, has led to security and economic problems for Israel. Since October 2000, there has been a significant increase in violence, primarily in the West Bank and Gaza Strip. As a result, negotiations between Israel and representatives of the

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Palestinian Authority have been sporadic and have failed to result in peace. We could be adversely affected by hostilities involving Israel, the interruption or curtailment of trade between Israel and its trading partners, or a significant downturn in the economic or financial condition of Israel. In addition, the sale of products manufactured in Israel may be adversely affected in certain countries by restrictive laws, policies or practices directed toward Israel or companies having operations in Israel.

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

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

Failure to comply with certain conditions and restrictions associated with tax benefits provided to Ormat Systems Ltd. by the Government of Israel as an ‘‘approved enterprise’’ may require us to refund such tax benefits and pay future taxes in Israel at higher rates.

Our subsidiary, Ormat Systems Ltd., which we refer to as Ormat Systems, has received ‘‘approved enterprise’’ status under Israel’s Law for Encouragement of Capital Investments, 1959, with respect to two of its investment programs. As an approved enterprise, our subsidiary is exempt from Israeli income taxes with respect to revenues derived from the approved investment program for a period of two years commencing on the year it first generates profits from the approved investment program, and thereafter such revenues are subject to a reduced Israeli income tax rate of 25% for an additional five years. These benefits are subject to certain conditions set forth in the certificate of approval from Israel’s Investment Center, which include, among other things, a requirement that Ormat Systems comply with Israeli intellectual property law, that all transactions between Ormat Systems and our affiliates be at arms length, and that there will be no change in control of, on a cumulative basis, more than 49% of Ormat Systems’ capital stock (including by way of a public or private offering) without the prior written approval of the Investment Center. If Ormat Systems does not comply with these conditions, in whole or in part, it would be required to refund the amount of tax benefits (as adjusted by the Israeli consumer price index and for accrued interest) and would no longer benefit from the reduced Israeli tax rate, which could have an adverse effect on our financial condition, future results and cash flow. If Ormat Systems distributes dividends out of revenues derived during the tax exemption period from the approved investment program, it will be subject, in the year in which such dividend is paid, to Israeli income tax on the distributed dividend.

If our parent defaults on its lease agreement with the Israel Land Administration, or is involved in a bankruptcy or similar proceeding, our rights and remedies under certain agreements pursuant to which we acquired our products business and pursuant to which we sublease our land and manufacturing facilities from our parent may be adversely affected.

We acquired our business relating to the manufacture and sale of products for electricity generation and related services from our parent, Ormat Industries. In connection with that acquisition, we entered into a sublease with Ormat Industries for the lease of the land and facilities in Yavne, Israel where our manufacturing and production operations are conducted and where our Israeli offices are located. Under the terms of our parent’s lease agreement with the Israel Land Administration, any sublease for a period of more than five years may require the prior approval of the Israel Land Administration. As a result, the initial term of our sublease with Ormat Industries is for a period of four years and eleven months beginning on July 1, 2004, extendable to twenty-five years less one day (which includes the initial term). The consent of the Israel Land Administration was obtained for a period of the shorter of (i) 25 years or (ii) the remaining period of the underlying lease agreement with the Israel Land Administration, which terminates between 2018 and 2047. If our parent were to breach its obligations to the Israel Land Administration under its lease agreement, the Israel Land Administration could terminate the lease agreement and, consequently, our sublease would terminate as well.

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As part of the acquisition described in the preceding paragraph, we also entered into a patent license agreement with Ormat Industries, pursuant to which we were granted an exclusive license for certain patents and trademarks relating

to certain technologies that are used in our business. If a bankruptcy case were commenced by or against our parent, it is possible that performance of all or part of the agreements entered into in connection with such acquisition (including the lease of land and facilities described above) could be stayed by the bankruptcy court in Israel or rejected by a liquidator appointed pursuant to the Bankruptcy Ordinance in Israel and thus not be enforceable. Any of these events could have a material and adverse effect on our business, financial condition, future results and cash flow.

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

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

The agreements pursuant to which most of our subsidiaries have incurred debt restrict the ability of these subsidiaries to pay dividends, make distributions or otherwise transfer funds to us prior to the satisfaction of other obligations, including the payment of operating expenses, debt service and replenishment or maintenance of cash reserves. In the case of some of our projects, such as the Mammoth project, there may be certain additional restrictions on dividend distributions pursuant to our agreements with our partners. Further, if we elect to receive distributions of earnings from our foreign operations, we may incur United States taxes on account of such distributions, net of any available foreign tax credits. In all of the foreign countries where our existing projects are located, dividend payments to us are also subject to withholding taxes. Each of the events described above may reduce or eliminate the aggregate amount of revenues we can receive from our subsidiaries.

Some of our directors and executive officers who also hold positions with our parent may have conflicts of interest with respect to matters involving both companies.

Three of our seven directors are directors and/or officers of Ormat Industries, namely Lucien Bronicki, Dita Bronicki and Yoram Bronicki. In addition, four of our executive officers are also executive officers of Ormat Industries. Specifically, our Chairman, Director and Chief Technology Officer, Lucien Bronicki, is the Chairman of our parent; our Chief Executive Officer, President and Director, Dita Bronicki, is the Chief Executive Officer of our parent; our Chief Financial Officer, Joseph Tenne, is the Chief Financial Officer of our parent; and Etty Rosner our Vice President — Contract Administrator and Corporate Secretary is the Corporate Secretary of our parent. These directors and officers owe fiduciary duties to both companies and may have conflicts of interest on matters affecting both us and our parent, and in some circumstances may have interests adverse to our interests.

Our controlling stockholders may take actions that conflict with your interests.

Ormat Industries Ltd. holds approximately 64.0% of our common stock. Bronicki Investments Ltd. holds approximately 28.12% of the outstanding shares of common stock of Ormat Industries Ltd. as of February 28, 2007 (27.50% on a fully diluted basis). Bronicki Investments Ltd. is a privately held Israeli company and is controlled by Lucien and Dita Bronicki. Because of these holdings, our parent company will be able to exercise control over all matters requiring stockholder approval, including the election of directors, amendment of our certificate of incorporation and approval of significant corporate transactions, and they will have significant control over our management and policies. The directors elected by these stockholders will be able to significantly influence decisions affecting our capital structure. This control may have the effect of delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in their best interest. For example, our controlling stockholders will be able to control the sale or other disposition of our products business to another entity or the transfer of such business outside of the State of Israel; as such action requires the affirmative vote of at least 75% of our outstanding shares.

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

The market price of our common stock is likely to 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-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;
- announcements of significant contracts by us or our competitors;
- changes in our pricing policies or the pricing policies of our competitors;
- 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; and
- general economic conditions.

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

Future sales of common stock by some of our existing stockholders could cause our stock price to decline.

As of the date of this report, our parent, Ormat Industries Ltd., holds approximately 64% of our outstanding common stock and some of our directors, officers and employees also hold shares of our outstanding common stock. Sales of such shares in the public market, as well as shares we may issue upon exercise of outstanding options, could cause the market price of our common stock to decline. On November 10, 2004, we entered into a registration rights agreement with Ormat Industries whereby Ormat Industries may require us to register our common stock held by it or its directors, officers and employees with the Securities and Exchange Commission or to include our common stock held by it or its directors, officers and employees in an offering and sale by us.

Provisions in our charter documents and Delaware law may delay or prevent acquisition of us, which could adversely affect the value of our common stock.

Our restated certificate of incorporation and our bylaws contain provisions that could make it harder for a third party to acquire us without the consent of our Board of Directors. These provisions do not permit actions by our stockholders by written consent. In addition, these provisions include procedural requirements relating to stockholder meetings and stockholder proposals that could make stockholder actions more difficult. Our Board of Directors is classified into three classes of directors serving staggered, three-year terms and may be removed only for cause. Any vacancy on the Board of Directors may be filled only by the vote of the majority of directors then in office. Our Board

of Directors has the right to issue preferred stock without stockholder approval, which could be used to institute a ‘‘poison pill’’ that would work to dilute the stock ownership of a potential hostile acquirer,

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effectively preventing acquisitions that have not been approved by our Board of Directors. Delaware law also imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. Although we believe these provisions provide for an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our Board of Directors, these provisions apply even if the offer may be considered beneficial by some stockholders.

The Sarbanes-Oxley Act of 2002 imposes significant regulatory, corporate and operational requirements on the Company. Failure to comply with such provisions may have significant adverse consequences to the Company

As a public company, we are subject to the Sarbanes-Oxley Act of 2002 (the SOX Act). The SOX Act contains a variety of provisions affecting public companies, including but not limited to, corporate governance requirements, our relationship with our auditors, evaluation of our internal disclosure controls and procedures and evaluation of our internal control over financial reporting. See Management’s Report on Internal Control over Financial Reporting and Item 9A. — ‘‘Controls and Procedures’’.

ITEM 1B. UNRESOLVED STAFF COMMENTS

On December 29, 2006, we received a comment letter from the staff of the Division of Corporation Finance of the SEC, with respect to our annual report on Form 10-K for the year ended December 31, 2005. We responded to the staff’s comments in a letter dated January 29, 2007. We believe that we have resolved all of the staff’s comments, with the exception of one staff comment relating to the accounting treatment in the statement of cash flows and in the statement of operations of the lease and lease back transaction of the Puna project. . Our response to the staff included a detailed discussion of relevant accounting authority and our analysis undertaken in reaching a decision to so present and account for the Head Lease. On March 9, 2007, we received a follow up letter from the staff, asking us for an explanation of our lease out, lease in transactions and our analysis and the accounting authority for our conclusion regarding the accounting treatment of such transactions. As such, this comment remains unresolved. The Company believes that it has properly accounted for the Puna lease transaction in accordance with the provisions of SFAS No. 13, Accounting for Leases.

ITEM 2. PROPERTIES

We currently lease corporate offices at 6225 Neil Road, Reno, Nevada 89511-1136. We also occupy an approximately 66,000 square meter office and manufacturing facility located in the Industrial Park of Yavne, Israel, which we sublease from Ormat Industries. See ‘‘Certain Relationships and Related Transactions’’. We also lease small offices in each of the countries in which we operate.

We believe that our current facilities are adequate for our operations as currently conducted. If additional facilities are required, we believe that we could obtain additional facilities at commercially reasonable prices.

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

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

ITEM 3. LEGAL PROCEEDINGS

There were no material developments in any legal proceedings to which the Company is a party during the fiscal year 2006, other than as described below.

As a result of our acquisition of the Steamboat 1 and 1A plants, our subsidiary Steamboat Geothermal LLC has become a party to litigation pending in the Second Judicial District Court in Washoe County, Nevada with Geothermal Development Associates and Delphi Securities, Inc. In April 2002, these plaintiffs initiated a lawsuit against the former owner and operator of the Steamboat

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1/1A project. The plaintiffs dispute amounts owed to them pursuant to an agreement, dated July 14, 1985, pursuant to which Geothermal Development Associates assigned all of its right, title, and interest in the subject geothermal leasehold property in exchange for a net operating royalty interest in the revenues of the Steamboat 1 plant. The plaintiffs claim entitlement to damages based upon the following three allegations, which we deny: (i) that the actions of the former owner in developing the Steamboat 1A plant have decreased the output of the Steamboat 1 plant; (ii) that general, administrative, and corporate expenses included by the former owner in the calculation of the net royalty amount were overstated for the years 2000 and 2001; and (iii) that, in addition to its royalty interest in the revenues from the Steamboat 1 plant, plaintiffs are entitled to a net revenue royalty interest from the Steamboat 1A plant. The matter was originally set for a trial in September 2003, but the trial date was adjourned in order to allow the plaintiffs to obtain substitute counsel. Initial evidentiary disclosures and discovery requests had been made before the trial was adjourned. No dispositive motions are pending before the Court and the trial date has not been rescheduled. As of December 31, 2005 and January 9, 2006, Steamboat Geothermal LLC entered into a sales, settlement and release agreement and an assignment agreement, respectively, with Woodside Properties LLC, the assignee of 37% of Geothermal Development Associates’ right to net operating revenues, whereby Steamboat Geothermal LLC was assigned 37% of the net operating revenues of Steamboat 1 in partial settlement of the above mentioned dispute with Geothermal Development Associates and Delphi Securities, Inc. The plaintiffs also assert that, in addition to the amounts they claim are owed to them, they are entitled to interest on those amounts, as well as a reasonable net operating royalty payment from our Burdette project. We believe that such assertion is without merit, and that any outcome of such litigation or any settlement discussions will not have a material impact on our results of operations. On November 14, 2006, the parties agreed to dismiss plaintiff Delphi Securities, Inc. from the case with prejudice. The case is scheduled for mediation on April 10-11, 2007.

In connection with the power purchase agreements for the Ormesa project, Southern California Edison has expressed its intent not to pay the contract rate for the power supplied by the GEM 2 and GEM 3 plants to the Ormesa project. Southern California Edison contends that California ISO real-time prices should apply, while management believes that SP-15 prices quoted by NYMEX should apply. According to Southern California Edison’s estimation, the amount under dispute is approximately $2.5 million. The parties have signed an interim agreement; whereby Southern California Edison will continue to procure the GEM 2 and GEM 3 power at the current energy rate of 5.37 cents/kWh until May 1, 2007. In addition, a long-term power purchase agreement is expected to be entered into for the GEM 2 and GEM 3 power. The negotiations in connection with the long-term power purchase agreement are still under way and there is no guarantee that such negotiations will be successfully completed. Management believes that such settlement agreement will not have a material financial impact on us.

One of our subsidiaries, Ormat Inc., is a party in a third-party complaint originally filed on November 15, 2005 by Lacy M. Henry and Judy B. Henry (the Henrys) in a bankruptcy proceeding in the United States Bankruptcy Court for the Eastern District of North Carolina. The Henrys are debtors in a Chapter 11 bankruptcy filed in the Bankruptcy Court. The Henrys were the sole shareholders of MPS Generation, Inc. (MPSG). We entered into a supply contract with MPSG dated as of December 29, 2003, under which we were retained as a subcontractor to produce four waste heat energy converters for a project for which MPSG had entered into a contract with Basin Electric Power Cooperative (Basin). Basin filed a lawsuit on February 24, 2005 against, among others, MPSG and the Henrys in the United States District Court for the District of North Dakota, alleging various causes of action including breach of contract, actual and constructive fraud, and conversion, and demanding the piercing of MPSG's corporate veil to establish the personal liability of the Henrys for MPSG's debts. On September 15, 2005, Basin filed a complaint commencing the bankruptcy adversary proceeding, seeking a determination that the claims which Basin alleged against the Henrys in the North Dakota lawsuit were not dischargeable. On November 15, 2005, the Henrys answered Basin's complaint in the bankruptcy proceeding and also filed a third-party complaint against us, alleging that to the extent the Henrys are found personally liable to Basin for MPSG's debts, the Henrys have claims against us for breach of contract/breach of warranty, tortious interference with contract, unfair

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or deceptive trade practices and fraud. The Henrys alleged damages in excess of $100 million. On December 15, 2005, we filed an answer denying the Henrys' claims and asserting counterclaims against the Henrys. Our subsidiary filed a motion to dismiss the Henrys' claims on January 31, 2006. On March 21, 2006, Basin filed an Amended Complaint in the bankruptcy proceeding, consolidating the causes of action it brought in the North Dakota lawsuit. In their answer to Basin's Amended Complaint, the Henrys raised the same third party claims against our subsidiary. On May 11, 2006, the Bankruptcy Court entered an order denying our subsidiary's motion to dismiss the Henrys' claims against it, but staying the Henrys' litigation against our subsidiary pending the resolution of Basin's alter ego claims against the Henrys. In its answer to Basin's Amended Complaint, MPSG asserted third party claims against our subsidiary similar to those claims raised by the Henrys. We believe that we have no liability to the Henrys or to MPSG and intend to defend vigorously against the Henrys' and MPSG's claims in the bankruptcy proceeding. A trial on all issues raised in the bankruptcy proceeding is scheduled to begin in September 2007 in the Bankruptcy Court.

From time to time, we (including our subsidiaries) are a party to various other lawsuits, claims and other legal and regulatory proceedings that arise in the ordinary course of our (and their) 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, we accrue reserves in accordance with U.S. generally accepted accounting principles. We do not believe that any of these proceedings, individually or in the aggregate, would materially and adversely affect our business, financial condition, future results or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the quarter ended December 31, 2006.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol ''ORA''. Public trading of our stock commenced on November 11, 2004. Prior to that, there was no public market for our stock. The approximate number of holders of record of our common stock was 8 on February 28, 2007. On February 28, 2007, our stock's closing price as reported on the New York Stock Exchange was $38.82 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 of Directors 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 of Directors would prevent us from meeting such business plan or obligations.

Notwithstanding this policy, dividends will be paid only when, as and if approved by our Board of Directors out of funds legally available therefore. The actual amount and timing of dividend payments will depend upon our financial condition, results of operations, business prospects and such other matters as the board may deem relevant from time to time. Even if profits are available for the payment of dividends, the Board of Directors could determine that such profits should be retained for an extended period of time, used for working capital purposes, expansion or acquisition of businesses or any other appropriate purpose. As a holding company, we are dependent upon the earnings and cash flow of our subsidiaries in order to fund any dividend distributions and, as a result, we may not be able to pay dividends in accordance with our policy. Our Board of Directors may, from time to time, examine our dividend policy and may, in its absolute discretion, change such policy.

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

Date Declared	Dividend Amount per Share	Record Date	Payment Date
March 22, 2005	$ 0.03	April 4, 2005	April 18, 2005
May 10, 2005	$ 0.03	May 23, 2005	June 6, 2005
August 11, 2005	$ 0.03	August 22, 2005	September 1, 2005
November 9, 2005	$ 0.03	November 29, 2005	December 6, 2005
March 7, 2006	$ 0.03	March 28, 2006	April 4, 2006
May 9, 2006	$ 0.04	May 23, 2006	May 30, 2006
August 6, 2006	$ 0.04	August 23, 2006	August 30, 2006
November 7, 2006	$ 0.04	November 30, 2006	December 13, 2006
February 27, 2007	$ 0.07	March 21, 2007	March 29, 2007

High/Low Stock Prices:

Ormat Technologies, Inc. (ORA) — High and Low Prices for the years 2005 and 2006, and from January 1 until February 28, 2007:

	First Quarter 2005	Second Quarter 2005	Third Quarter 2005	Fourth Quarter 2005	First Quarter 2006	Second Quarter 2006	Third Quarter 2006	Fourth Quarter 2006	January 1 to February 28, 2007
High:	$ 16.50	$ 19.20	$ 24.10	$ 29.10	$ 43.42	$ 40.54	$ 38.59	$ 40.98	$ 44.59
Low:	$ 14.50	$ 13.88	$ 18.25	$ 18.80	$ 27.75	$ 31.64	$ 31.75	$ 32.01	$ 37.11

Stock Performance Graph:

The following performance graph represents the cumulative total shareholder return for the period November 11, 2004 (the date upon which trading of the Company's common stock commenced) through December 31, 2006 for our common stock, as compared to the Standard and Poor's Composite 500 Index, and a peer group.

	11/11/2004	12/31/2004	12/31/2005	12/31/2006
Ormat Technologies, Inc.	$ 100	$ 109	$ 174	$ 245
Standard & Poor's Composite 500 Index	$ 100	$ 108	$ 111	$ 126
IPP Peers*	$ 100	$ 113	$ 144	$ 210
Renewable Peers*	$ 100	$ 117	$ 236	$ 220

*Independent Power Producer (IPP) Peers are The AES Corporation, NRG Energy Inc. and International Power PLC Renewable energy (Renewable) Peers are Acciona S.A., Evergreen Solar Inc. and Energy Conversion Devices Inc.

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

Equity Compensation Plan Information

For information on our equity compensation plan, refer to Item 12 ''Security Ownership of Certain Beneficial Owners and Management''.

Unregistered Sales of Equity Securities and Use of Proceeds from Registered Securities

None.

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, 2006, 2005 and 2004 and as of December 31, 2006 and 2005 from our audited consolidated financial statements set forth in Part II Item 8 of this annual report. We have derived the selected consolidated financial data for the years ended December 31, 2003 and 2002, and as of December 31, 2004, 2003 and 2002 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 set forth in Part II Item 8 of this annual report.

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except per share data)				
Statements of Operations Data:					
Revenues:					
Electricity:					
Energy and capacity	$ 106,682	$ 104,975	$ 100,281	$ 77,752	$ 65,491
Lease portion of energy and capacity	86,115	70,963	58,550	—	—
Lease income	2,686	1,431	—	—	—
Total Electricity	195,483	177,369	158,831	77,752	65,491
Products	73,454	60,623	60,399	41,688	20,138
Total revenues	268,937	237,992	219,230	119,440	85,629
Cost of revenues:					
Electricity:					
Energy and capacity	77,768	70,328	63,300	46,726	33,482
Lease portion of energy and capacity	41,345	30,215	26,442	—	—
Lease expense	5,243	3,072	—	—	—
Total Electricity	124,356	103,615	89,742	46,726	33,482
Products	51,215	45,236	46,336	29,494	17,293
Total cost revenues	175,571	148,851	136,078	76,220	50,775
Gross margin:	93,366	89,141	83,152	43,220	34,854
Operating expenses (income):					
Research and development expenses	2,983	3,036	2,175	1,391	1,503
Selling and marketing expenses	10,361	7,876	7,769	7,087	6,051
General and administrative expenses	18,094	14,320	11,609	9,252	7,073
Gain on sale of geothermal resource rights	—	—	(845)	—	—
Operating income	61,928	63,909	62,444	25,490	20,227
Other income (expense):					
Interest income	6,560	4,308	1,316	607	609
Interest expense	(30,961)	(55,317)	(42,785)	(8,120)	(6,179)
Foreign currency translation and transaction loss	(704)	(439)	(146)	(316)	(323)
Other non-operating income	694	512	112	464	1,195
Income from continuing operations					

before income taxes, minority interest and equity in income of investees	37,517	12,973	20,941	18,125	15,529
Income tax provision	(6,403)	(4,690)	(6,609)	(2,506)	(6,135)
Minority interest in earnings of subsidiaries	(813)	—	(108)	(519)	(1,194)
Equity in income of investees	4,146	6,894	3,567	559	314
Income from continuing operations	34,447	15,177	17,791	15,659	8,514
Discontinued operations:					
Loss from operations of discontinued activities in Kazakhstan	—	—	—	—	(3,114)
Loss on sale of Kazakhstan operations	—	—	—	—	(6,444)
Income (loss) before cumulative effect of change in accounting principle	34,447	15,177	17,791	15,659	(1,044)
Cumulative effect of change in accounting principle (net of tax benefit of $125,000)	—	—	—	(205)	—
Net income (loss)	$ 34,447	$ 15,177	$ 17,791	$ 15,454	$ (1,044)

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except per share data)				
Basic earnings (loss) per share:					
Income from continuing operations	$ 1.00	$ 0.48	$ 0.72	$ 0.67	$ 0.37
Loss from discontinued operations	—	—	—	—	(0.41)
Cumulative effect of change in accounting principle	—	—	—	(0.01)	—
Net income (loss)	$ 1.00	$ 0.48	$ 0.72	$ 0.66	$ (0.04)
Diluted earnings (loss) per share:					
Income from continuing operations	$ 0.99	$ 0.48	$ 0.72	$ 0.67	$ 0.37
Loss from discontinued operations	—	—	—	—	(0.41)
Cumulative effect of change in accounting principle	—	—	—	(0.01)	—
Net Income (loss)	$ 0.99	$ 0.48	$ 0.72	$ 0.66	$ (0.04)
Weighted average number of shares used in computation of earnings (loss) per share:					
Basic	34,593	31,563	24,806	23,214	23,214
Diluted	34,707	31,609	24,806	23,214	23,214
Cash dividend per share declared during the year	$ 0.1500	$ 0.1200	$ 0.1025	$ —	$ —
Balance Sheet Data (at end of year):					
Cash and cash equivalents	$ 20,254	$ 26,976	$ 36,750	$ 8,873	$ 36,684
Working capital (deficit)	34,429	36,616	50,341	2,677	(79,853)
Property, plant and equipment, net (including construction-in process)	793,164	620,091	527,003	379,133	180,118
Total assets	1,160,102	914,480	850,088	543,138	287,378

Long-term debt (including current portion)	372,009	365,539	384,515	260,488	95,807
Notes payable to Parent (including current portion)	140,153	171,805	193,852	177,004	—
Stockholders' equity	440,794	182,259	167,914	36,975	27,837

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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

We are a leading vertically integrated company engaged in the geothermal and recovered energy power business. We design, develop, build, own and operate clean, environmentally friendly geothermal and recovered energy-based power plants using equipment that we design and manufacture. In addition, we sell the equipment we design and manufacture for geothermal electricity generation, recovered energy-based electricity generation, and other equipment for electricity generation to third parties. Our operations consist of two business segments. The first consists of the sale of electricity from our power plants, which we refer to as the Electricity Segment. The second consists of the design, manufacturing and sale of equipment for electricity generation, the installation thereof and the provision of services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy power plants, which we refer to as the Products Segment.

Our Electricity Segment mainly consists of our investment in power plants producing electricity from geothermal resources and, as of recently, from recovered energy resources. Our geothermal power plants include both power plants that we have built and power plants that we have acquired, while all of our recovered energy-based plants have been constructed by us. Our Products Segment consists of the design, manufacture and sale of equipment that generates electricity, principally from geothermal and recovered energy resources, but also using other fuel sources as well. Our Products Segment also includes, to the extent requested by our customers, the installation of our equipment and other related power plant installations and the provision of services relating to the engineering, procurement, construction, operation and maintenance of geothermal and recovered energy power plants. For the year ended December 31, 2006, our Electricity Segment represented approximately 72.7% of our total revenues, while our Products Segment represented approximately 27.3% of our total revenues during such year.

During the year ended December 31, 2006, total Electricity Segment revenues from the sale of electricity by our consolidated power plants (including revenues derived from the Zunil project, which was consolidated as of March 13, 2006) were $195.5 million. In addition, revenues from our 50% ownership of the Mammoth Project and from our 80% ownership of the Leyte Project for the year ended December 31, 2006 were $18.6 million. This additional data is

a Non-Generally Accepted Accounting Principles (Non-GAAP) financial measure as defined by the SEC. There is no comparable GAAP measure. Management believes that such Non-GAAP data is useful to the readers as it provides a more complete view on the scope of the activities of the power plants that we operate. Our investments in the Mammoth and Leyte projects are accounted for in our consolidated financial statements under the equity method and the revenues are not included in our consolidated revenues for the year ended December 31, 2006.

Our Electricity Segment operations are conducted in the United States and throughout the world. Since January 1, 2001, we have completed various acquisitions of geothermal power plants with an aggregate acquisition cost, net of cash received, of $526.7 million. In the year ended December 31,

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2006, we increased our net ownership interest in generating capacity by 19 MW through the acquisition of an additional 79.0% ownership interest in the Zunil project in Guatemala, thereby increasing our ownership interest in that project to 100%, as a result of which the project is now fully consolidated. In addition, we increased our net ownership interest in generating capacity by 32 MW through new construction, which includes our first four REG plants completed in the fourth quarter of 2006. We currently own or control as well as operate geothermal projects in the United States, Guatemala, Kenya, Nicaragua and the Philippines.

Our Products Segment operations are also conducted in the United States and throughout the world. During the year ended December 31, 2006, revenues attributable to our Products Segment were $73.5 million.

We have identified recovered energy-based power generation as a significant market opportunity for us in the United States and throughout the world. We expect that recovered energy generation projects will increase our revenues in both the Electricity Segment and the Products Segment.

During the year ended December 31, 2006, we recognized revenues in our Products Segment of approximately $25.0 million from REG compared to $8.5 million during the year ended December 31, 2005. During the year ended December 31, 2006 we received purchase orders for the supply and construction of REG plants in a total amount of $36.6 million, out of which we recognized revenues in the amount of $8.5 million in the year ended December 31, 2006. Our Electricity Segment is characterized by relatively predictable revenues generated by our power plants pursuant to long-term power purchase agreements, with terms which are generally up to 20 years. The price for electricity under all of the power purchase agreements is effectively a fixed price, except in the case of the power purchase agreement of the Puna project, which has a variable energy rate based on the local utility’s short run avoided costs (the incremental costs that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others). 81.2% of the electricity revenues generated in the year ended December 31, 2006, was derived from contracts with fixed energy rates, and therefore such revenues were not affected by the fluctuations in energy commodity prices.

Revenues attributable to our Products Segment, which are based on the sale of equipment and the provision of various services to our customers, may vary from period to period because of the timing of our receipt of purchase orders and the progress of our execution of each project. Our management assesses the performance of our two segments of operation differently. In the case of our Electricity Segment, when making decisions about potential acquisitions or the development of new projects, our management typically focuses on the internal rate of return of the relevant investment, relevant technical and geological matters and other relevant business considerations. Additionally, as part of our Electricity Segment, our management evaluates our operating projects based on the performance of such

projects in terms of revenues and expenses in contrast to projects that are under development, which our management evaluates based on costs attributable to each such project. By contrast, our management evaluates the performance of our Products Segment based on the timely delivery of our products, performance quality of our products and costs actually incurred to complete customer orders as compared to the costs originally budgeted for such orders.

During the year ended December 31, 2006, our total revenues increased by 13.0% (from $238.0 million to $268.9 million) over the previous year. During the years ended December 31, 2006 and 2005, our U.S. projects generated 1,894,227 MWh and 1,799,072 MWh, respectively, which include our 50% share in the Mammoth project. We were unable to realize fully the aggregate generating capacity of our power plants due to unexpected operational problems that we experienced at some of our plants, such as the Puna and Ormesa projects, and the delay in the commercial operation of the Desert Peak 2 plant, all of which are described in this report.

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Trends and Uncertainties

The geothermal industry in the United States has historically experienced significant growth followed by a consolidation of owners and operators of geothermal power plants. During the 1990's, growth and development in the geothermal industry occurred primarily in foreign markets and only minimal growth and development occurred in the United States. Since 2001, there has been increased demand for energy generated from geothermal resources in the United States as production costs for electricity generated from geothermal resources have become more competitive relative to fossil fuel generation, due to increasing natural gas prices and as a result of newly enacted legislative and regulatory incentives, such as state renewable portfolio standards. We see the increasing demand for energy generated from geothermal and other renewable resources in the United States and the further introduction of renewable portfolio standards as the most significant trends affecting our industry today and in the immediate future. The recent relative decline in oil and gas prices does not appear to have impacted the increasing demand for renewable energy. Our operations and the trends that from time to time impact our operations are subject to market cycles.

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

- In 2005 and 2006, our primary activity has been the implementation of our organic growth through the construction of new projects and enhancements of several of our existing projects, as discussed in Item 1 — ''Business — Our Power Generation Business'' in this annual report. As a result, growth in revenues and overall generating capacity has been more moderate than the previous two years, which were characterized by significant acquisitions. Nevertheless, we expect that this investment in organic growth will result in a significant increase in our total generating capacity and a corresponding increase in our consolidated revenues as well as in our operating income attributable to our Electricity Segment in 2007, as compared with 2006.
- We expect that the increased awareness of climate change may result in significant changes in the business and regulatory environment, which may create business opportunities for us going forward
- In the United States, we expect to continue to benefit from the increasing demand for renewable energy as a result of favorable legislation adopted by 23 states and the District of

Colombia, including California, Nevada and Hawaii (where we have been active in geothermal development and in which all of our U.S. geothermal projects are located). In each of these states, relevant legislation currently requires that an increasing percentage of the electricity supplied by electric utility companies operating in such states be derived from renewable energy resources until certain pre-established goals are met. We expect that the additional demand for renewable energy from utilities in such states will create additional opportunities for us to expand existing projects and build new power plants.

- On September 27, 2006, the California Global Warming Solutions Act of 2006 (the Act) was signed into law. The Act regulates most sources of greenhouse gas emissions and is expected to result in a reduction of carbon emissions to 1990 levels by 2020, representing a twenty-five percent reduction in greenhouse gas emissions. To accomplish this, the Act provides a framework for greenhouse gas emissions reductions through the use of emissions control technologies and other cost-effective reduction strategies, one of which may involve the use of market-based trading of emissions rights. The California Air Resources Board must adopt standards for implementing the Act by 2011. Although programs under the Act will take some time to develop, its requirements, particularly the creation of a market-based trading mechanism to achieve compliance with emissions caps, should be highly advantageous to in-state energy generating sources that have low carbon emissions such as geothermal energy.

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- On September 27, 2006, California also enacted legislation requiring that its renewable portfolio standard of 20% generation from renewable energy resources per year be met by December 2010, ahead of the previous legislative mandated target of December 2017. The California legislature is currently considering an increase to 33% by December 31, 2020.
- Outside of the United States, we expect that a variety of governmental initiatives, including 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, will create new opportunities for the development of new projects as well as create additional markets for our remote power units and other products.
- In pursuing new orders, we participate in tenders for projects and proposals for installations and identify and monitor markets, which utilize or plan to utilize geothermal energy, and in which geothermal resources are available. We also intend to continue to pursue growth in our recovered energy business, and we expect that the portion of revenues from our recovered energy business as a percentage of the total revenues from our Products Segment will increase.
- We expect to continue to generate the majority of our revenues from our Electricity Segment through the sale of electricity from our power plants. All of our current revenues from the sale of electricity are derived from fully-contracted payments under long-term power purchase agreements.
- Over the last year, competition from the wind and solar power generation industry has increased. While the current demand for renewable energy is large enough that this increased competition has not impacted our ability to obtain new power purchase agreements, it may create pressure on electricity prices.
- The viability of the geothermal resources utilized by our power plants depends on various factors such as the heat content of the geothermal reservoir, useful life of the reservoir (the term during which such geothermal reservoir has sufficient extractable fluids for our

operations) and operational factors relating to the extraction of the geothermal fluids. Our geothermal power plants may experience an unexpected decline in the capacity of their respective geothermal wells. Such factors, together with the possibility that we may fail to find commercially viable geothermal resources in the future, represent significant uncertainties we face in connection with our operations.

- As our power plants age, they may require increased maintenance with a resulting decrease in their availability.
- Our foreign operations are subject to significant political, economic and financial risks, which vary by country. Such risks include the ongoing privatization of the electricity industry in the Philippines, the partial privatization of the electricity sector in Guatemala, labor unrest in Nicaragua and the political uncertainty currently prevailing in Kenya. Although we maintain political risk insurance as an attempt to mitigate such risks, such insurance does not provide complete coverage with respect to all such risks.
- We continue to experience increases in the cost of raw materials required for our equipment manufacturing activities and equipment used in our power plants. We partially addressed the availability of drilling equipment by purchasing a drilling rig, which we expect will be supplied to us in the first half of 2007. We have experienced an increase in drilling costs and a shortage in drilling equipment, which we believe is the result of the high oil prices resulting in increased drilling activity in the marketplace. We also have experienced, and expect to continue to experience, an increase in construction costs, particularly in the United States, due to rising prices attendant to a significant increase in activities in the construction industry. An increase in such costs may have an adverse effect on our financial condition and results of operations.

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- The United States extended a tax subsidy and increased the amount of the tax subsidy for companies that use geothermal steam or fluid to generate electricity as part of the Energy Policy Act of 2005 that became law on August 8, 2005. The tax subsidy is a ‘‘production tax credit’’, which in 2006 was 1.9 cents per kWh and is adjusted annually for inflation. The production tax credit may be claimed on the electricity output of new geothermal power plants put into service by December 31, 2008. Credit may be claimed for ten years on the output from any new geothermal power plants put into service prior to December 31, 2008. We, as the owner of any project that would be put in service during the period ending December 31, 2008, would have to choose between this production tax credit and a 10% investment tax credit.
- The Energy Policy Act of 2005, as mentioned above, authorizes FERC to revise PURPA so as to terminate the obligation of electric utilities to purchase the output of a Qualifying Facility if FERC finds that there is an accessible competitive market for energy and capacity from the Qualifying Facility. The legislation does not affect existing power purchase agreements. We do not expect this change in law to affect our U.S. projects significantly, as all except one of our current contracts (our Steamboat 1 project, which sells its electricity to Sierra Pacific Power Company on a year-by-year basis) are long-term. FERC has recently issued a final rule that could eliminate the utility’s purchase obligation in four regions of the country. None of those regions includes a state in which our current projects operate. However, FERC has the authority under the Energy Policy Act of 2005 to act, on a case-by-case basis, to eliminate the mandatory purchase obligation in other regions. In the final rule, FERC expressly noted that the California Independent System Operator (CAISO) has satisfied one but not all of the

criteria for relief from the mandatory purchase obligation. If the utilities in the regions in which our domestic projects operate were to be relieved of the mandatory purchase obligation, they would not be required to purchase energy from the project in the region under Federal law upon termination of the existing power purchase agreement, which could have an adverse effect on our revenues.

- On July 21, 2006, the Bureau of Land Management and the Minerals Management Service (each part of the Department of the Interior) issued separate proposed rules intended to implement relevant provisions of the Energy Policy Act of 2005. If adopted as proposed, the proposed rules would revise existing federal regulations, dealing with the general geothermal leasing process for federal land, lease durations, work commitments, annual rental and credit of rental toward royalties, and royalty calculations. Key features of the proposed rules include a requirement that geothermal resources be offered through a competitive lease process; the introduction of a new royalty methodology, calculated on the basis of gross proceeds from the sale of electricity, rather than the ‘‘netback’’ calculation previously in use; the introduction of increased rental payments (that are creditable toward royalties owed), and a new scheme of lease terms and extensions. The proposed rules would also establish ‘‘production incentives’’ for new facilities and qualified expansion facilities that are put into commercial operation by August 8, 2011, in the form of a four-year 50% reduction in royalty from what would otherwise be due. The 50% reduction would apply to all of the electricity generated from a new facility, and to the incremental electricity generated by a qualified expansion facility. The provisions of the proposed rules dealing with fees, rental payments, and royalties would apply to geothermal leases issued after August 8, 2005. However, lessees under leases issued prior to August 8, 2005 may elect to convert their leases to the new regulatory framework. The 60-day period for public comments on the proposed rule has expired, but as of the date of this report, no further regulatory action to codify and implement the proposed rules has been published. We do not expect that such proposed rules will have a material impact on us.

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.

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Revenues attributable to our Electricity Segment are relatively predictable as they are derived from the sale of electricity from our power plants pursuant to long-term power purchase agreements; however, such revenues are subject to seasonal variations, as more fully described below in the section entitled ‘‘Seasonality’’. Electricity segment revenues may also be affected by higher-than-average ambient temperature, which could cause a decrease in power generation from our projects and by unplanned major maintenance activities related to our projects.

Our power purchase agreements generally provide for the payment of capacity payments, energy payments, or both. Generally, capacity payments are payments calculated based on the amount of time that our power plants are available to generate electricity. Some of our power purchase agreements provide for bonus payments in the event that we are able to exceed certain target levels and the potential forfeiture of payments if we fail to meet minimum target levels. Energy payments, on the other hand, are payments calculated based on the amount of electrical energy delivered to the relevant power purchaser at a designated delivery point. The rates applicable to such payments are either fixed

(subject, in certain cases, to certain adjustments) or are based on the relevant power purchaser's short run avoided costs (the incremental costs that the power purchaser avoids by not having to generate such electrical energy itself or purchase it from others). Our more recent power purchase agreements provide generally for energy payments alone with an obligation to compensate the off-taker for its incremental costs as a result of shortfalls in our supply.

The lease income related to the Puna lease transactions, which are accounted for as operating leases, is included as a separate line item in our Electricity Segment revenues (See ''Liquidity and Capital Resources''). For management purposes, we analyze such revenue on a combined basis with other revenues in our Electricity Segment.

As required by Emerging Issues Task Force (EITF) Issue No. 01-8, Determining Whether an Arrangement Contains a Lease, we have assessed all of our power purchase agreements agreed to, modified or acquired in business combinations on or after July 1, 2003, and concluded that all such agreements contained a lease element requiring lease accounting. Accordingly, revenue related to the lease element of the agreements is presented as ''lease portion of energy and capacity'' revenue, with the remaining revenue related to the production and delivery of the energy presented as ''energy and capacity'' revenue in our consolidated financial statements.

As the lease revenue and the energy and capacity revenues are derived from the same arrangement and both fall within our Electricity Segment, we analyze such revenues, and related costs, on a combined basis for management purposes.

Revenues attributable to our Products Segment are generally less predictable than revenues from our Electricity Segment because larger customer orders for our products are typically a result of our winning tenders issued by potential customers in connection with projects they are developing. Such projects often take a long time to design and develop and are often subject to various contingencies such as the customer's ability to raise the necessary financing for a project. As a result, 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, our revenues from our Products Segment fluctuate (and at times, extensively) from period to period.

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

	Revenues in Thousands Year Ended December 31,			% of Revenues for Period Indicated Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
Revenues						
Electricity Segment	$ 195,483	$ 177,369	$ 158,831	72.7%	74.5%	72.4%
Products Segment	73,454	60,623	60,399	27.3%	25.5%	27.6%
Total	$ 268,937	$ 237,992	$ 219,230	100.0%	100.0%	100.0%

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Geographical breakdown of revenues

For the years ended December 31, 2006, 2005, and 2004, respectively, 83.3%, 87.8% and 84.7% of the revenues attributable to our Electricity Segment were generated in the United States.

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

	Revenues in Thousands Year Ended December 31,			% of Revenues for Period Indicated Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
United States	$ 162,844	$ 155,646	$ 134,576	83.3%	87.8%	84.7%
Foreign	32,639	21,723	24,255	16.7	12.2	15.3
Total	$ 195,483	$ 177,369	$ 158,831	100.0%	100.0%	100.0%

In the years ended December 31, 2004 and 2005 we did not have material products sales in the United States. In the year ended December 31, 2006 we recognized revenues of $10.5 million in our Products segments from sales in the United States.

Seasonality

The demand for the electricity generated by our domestic projects and the prices paid for such electricity pursuant to some of our power purchase agreements are subject to seasonal variations. The demand for electricity from the Heber 1 and 2 projects, the Mammoth project and the Ormesa project is the highest in the summer months of June through September, because the power purchaser for those projects, Southern California Edison, delivers more electricity to its California markets during such period in order to meet demand for air conditioning and other energy-intensive cooling systems utilized during such summer months. The demand for electricity from the Steamboat complex and the Brady project is more balanced, consisting of both summer and winter peaks that reflect the greater temperature variations in Nevada. The demand for electricity from the Puna project is balanced due to the equatorial temperature in Hawaii (with less pronounced temperature variations during the year). In most of our power purchase agreements in California, the capacity rates payable pursuant to the applicable power purchase agreement are higher in the summer months and as a result we receive higher revenues during such months. In contrast, there are no significant changes in prices during the year payable pursuant to our power purchase agreement for the Puna project and the Nevada projects. In the winter, due principally to the lower ambient temperature, our power plants produce more energy and as a result we receive higher energy revenues. However, the higher capacity payments payable by Southern California Edison in California in the summer months as a result of the increase in demand and in prices have a more significant impact on our revenues than that of the higher energy revenues generally generated in winter due to increased efficiency, and as a result our revenues are generally higher in the summer than in the winter.

Breakdown of Expenses

Electricity Segment

The principal expenses attributable to our operating projects include operation and maintenance expenses such as salaries, equipment expenses, costs of parts and chemicals, costs related to third-party services, lease expenses, royalties, startup and auxiliary electricity purchases, property taxes and insurance and, for the California projects, transmission charges, scheduling charges and purchases of sweet water for use in our plant cooling towers. Some of these expenses, such as parts, third-party services and major maintenance, are not incurred on a regular basis, which results in fluctuations in our expenses and our results of operations for individual projects from quarter to quarter. The lease expense related to the Puna lease transactions is included as a separate line item in our Electricity Segment cost of revenues (See ‘‘Liquidity and Capital Resources’’). For management purposes, we analyze such costs on a combined basis with other cost of revenues in our Electricity Segment.

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Payments made to government agencies and private entities on account of site leases where plants are located are included in cost of revenues. Royalty payments are payments made as compensation for the right to use certain geothermal resources and are included in cost of revenues, and are paid as a percentage of the revenues derived from the associated geothermal rights. For the year ended December 31, 2006, royalties were approximately 3.9% of the Electricity Segment revenues.

Products Segment

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

Cash, Cash Equivalents and Marketable Securities

Our cash, cash equivalents and marketable securities as of December 31, 2006 increased to $116.7 million from $70.5 million as of December 31, 2005. This increase is principally due to the combination of the $135.1 million net proceeds from our follow-on offering in April 2006 of 4,025,000 shares of common stock at a price of $37.50 per share, the $92.4 million net proceeds from our sale of 2,500,000 shares of common stock to Lehman Brothers in a block trade in December 2006 at a price of $37.50 per share, and $73.0 million derived from operating activities in the year ended December 31, 2006. During the year ended December 31, 2006, we used $159.5 million of our cash resources to fund capital expenditures and $22.8 million for acquisitions and to repay long-term debt to our parent and to third parties.

Critical Accounting Policies

Our significant accounting policies are more fully described in Note 1 to our audited consolidated financial statements set forth in Part II Item 8 of this annual report. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations. In applying these critical accounting policies, 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. Our critical accounting policies include:

- Revenues and Cost of Revenues. Revenues related to the sale of electricity from our geothermal and recovered energy-based power plants and capacity payments paid in connection with such sales, are recorded based upon output delivered and capacity provided by such power plants at rates specified pursuant to the relevant power purchase agreements. For power purchase agreements agreed to, modified or acquired in business combinations on or after July 1, 2003 (effective date of Emerging Issues Task Force Issue (EITF) No. 01-08, Determining Whether an Arrangement Contains a Lease), revenues related to the lease element of the power purchase agreements are included as ''lease portion of energy and capacity'' revenues, with the

remaining revenues related to the production and delivery of energy is presented as ‘‘energy and capacity’’. Lease income and lease expense are recognized ratably over the lease periods. 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. Revenues generated from the construction of geothermal and recovered energy power plant equipment and other equipment on behalf of third parties is recognized on the percentage completion method, which is the relationship between costs

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actually incurred and total estimated costs to completion. Such cost estimate is made by management in part based on prior operations and in part based on specific project characteristics and designs. If management’s estimates utilized with respect to our Products Segment of total estimated costs to completion are inaccurate, then the percentage of completion will also be inaccurate and thus lead management to over or under-estimate the gross margins for our Products Segment. Provisions for estimated losses relating to 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 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.

- Property, Plant and Equipment. Property, plant and equipment are stated at cost. All costs associated with the acquisition, development and construction of power plant facilities are capitalized. Major improvements are capitalized and repairs and maintenance (including major maintenance) costs are expensed. We estimate that the useful life of our power plants coincides with the term of the power purchase agreement; however, it is possible that the power plants may last longer than the related power purchase agreement. We periodically re-evaluate the estimated useful life of the power plants, which may result in our revising the useful life to a longer period at a future date.
- Impairment of Long-lived Assets and Long-lived Assets to Be Disposed of. Long-lived assets consist of property, plant and equipment, power purchase agreements and unconsolidated investments and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated future net undiscounted cash flows expected to be generated by the relevant asset. The significant assumptions that we use in estimating our undiscounted future cash flows include: (i) projected generating capacity of the project and rates to be received under the respective power purchase agreements, and (ii) projected operating expenses of the relevant project. If 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 the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. Our assessment regarding the existence of impairment factors is based on market conditions, operational performance and legal factors relating to our business. Our review of existing factors and the resulting appropriate carrying value of our long-lived assets are subject to judgment and estimates that management is required to make. We believe that no impairment exists for our long-lived assets; however, future estimates as to the recoverability of such assets may change based on revised circumstances.
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Obligations Associated with the Retirement of Long-Lived Assets. Effective January 1, 2003, we adopted Statement of Financial Accounting Standards (SFAS) No. 143 of the Financial Accounting Standards Board (FASB), Accounting for Obligations Associated with the Retirement of Long-Lived Assets. Pursuant to SFAS No. 143, which was amended by FASB Interpretation (FIN) No. 47, Accounting for Conditional Retirement Obligations, an Interpretation of FASB Statement No.143, entities are required to record the fair market value of any legal liability related to the retirement of any of its assets in the period in which such liability is incurred. Our liabilities related to the retirement of our assets include our obligation to plugging wells upon termination of our operating activities, the dismantling of our geothermal 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, an entity either settles the obligation for its

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recorded amount or incurs a gain or a loss with respect thereto, as applicable. We estimate the costs related to such liabilities and if such estimates are incorrect, then the capitalized costs and carrying amount of the related long-lived asset will change and as a result may affect our consolidated financial condition and results of operations.

- 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 currently 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.

We maintain a risk management strategy that incorporates the use of interest rate swaps and interest rate caps to minimize significant fluctuation in cash flows and/or earnings that are caused by interest rate volatility. Gain 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 are subsequently reclassified into earnings when interest on the related debt is paid. Gain or losses on contracts that are not designated to qualify as a cash flow hedge are included as a component of interest expense.

- Consolidation of Variable Interest Entities. In January 2003, the FASB issued FIN No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB 51, as amended by FIN No. 46R in December 2003. Among other things, FIN No. 46R generally deferred the effective date of FIN No. 46 to the quarter ended March 31, 2004. The objectives of FIN No. 46R are to provide guidance on the identification of Variable Interest Entities, which we refer to as VIEs, for which control is achieved through means other than ownership of a majority of the voting interest of the entity, and how to determine which company (if any), as the primary beneficiary, should consolidate such VIE. A variable interest in a VIE, by definition, is an asset, liability, equity, contractual arrangement or other economic interest that absorbs the entity's economic variability.

Effective as of March 31, 2004, we adopted FIN No. 46R. In connection with the adoption of FIN No. 46R, we concluded that Ormat Leyte Co., Ltd. (OLCL), in which we have an 80% ownership interest, should be

deconsolidated. OLCL's operating results were accounted for using the consolidation method of accounting for the three-month period ended March 31, 2004 and, effective April 1, 2004, our ownership interest in OLCL is accounted for using the equity method of accounting.

- Accounting for Income Taxes. As part of the process of preparing our consolidated financial statements in accordance with SFAS No. 109, Accounting for Income Taxes, we are required to estimate our income tax in each of the jurisdictions in which we operate. This process requires us to estimate our actual current tax exposure and make an assessment of temporary differences resulting from differing treatment of items for tax and accounting purposes. Such differences result in deferred tax assets and liabilities which are included in our consolidated balance sheet. We must then assess the likelihood that our net deferred tax assets will be recovered from future taxable income and, to the extent we believe that such recovery is not likely, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase such allowance in a period, we must include an expense within the tax provision in our consolidated statement of operations. Management uses significant judgment in determining our deferred tax assets and liabilities and any valuation allowance recorded against our net deferred tax assets. In the event that we generate taxable income in a particular jurisdiction in which we operate and in which we have net operating loss carryforwards for which a deferred tax valuation allowance has been established, we may be required to adjust our valuation allowance. Realization of the deferred tax assets and investment tax credits is dependent on generating sufficient taxable income prior to expiration

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of the loss carryforwards. Although realization is not assured, management believes it is more likely than not that the deferred tax asset as of December 31, 2006 will be realized. We account for investment tax credits and for production tax credits as a reduction to income tax in the year in which the credits arise.

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.

Results of Operations

Our historical operating results in dollars and as a percentage of total revenues are presented below. The different periods described below may not be comparable, as a result of the effects on our historical operating results of our recent acquisitions and enhancements of acquired projects and construction of new projects.

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share data)		
Statements of Operations Historical Data:			
Revenues:			
Electricity Segment	$ 195,483	$ 177,369	$ 158,831

Products Segment	73,454	60,623	60,399
	268,937	237,992	219,230
Cost of revenues:			
Electricity Segment	124,356	103,615	89,742
Products Segment	51,215	45,236	46,336
	175,571	148,851	136,078
Gross margin:			
Electricity Segment	71,127	73,754	69,089
Products Segment	22,239	15,387	14,063
	93,366	89,141	83,152
Operating expenses (income):			
Research and development expenses	2,983	3,036	2,175
Selling and marketing expenses	10,361	7,876	7,769
General and administrative expenses	18,094	14,320	11,609
Gain on sale of geothermal resource rights	—	—	(845)
Operating income	61,928	63,909	62,444
Other income (expense):			
Interest income	6,560	4,308	1,316
Interest expense	(30,961)	(55,317)	(42,785)
Foreign currency translation and transaction loss	(704)	(439)	(146)
Other non-operating income	694	512	112
Income before income taxes, minority interest and equity in income of investees	37,517	12,973	20,941
Income tax provision	(6,403)	(4,690)	(6,609)
Minority interest in earnings of subsidiaries	(813)	—	(108)
Equity in income of investees	4,146	6,894	3,567
Net income	$ 34,447	$ 15,177	$ 17,791
Earnings per share:			
Basic	$ 1.00	$ 0.48	$ 0.72
Diluted	$ 0.99	$ 0.48	$ 0.72
Weighted average number of shares used in computation of earnings per share:			
Basic	34,593	31,563	24,806
Diluted	34,707	31,609	24,806

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	Year Ended December 31,		
	2006	2005	2004
Statements of Operations Percentage Data:			
Revenues:			
Electricity Segment	72.7%	74.5%	72.4%
Products Segment	27.3	25.5	27.6
	100.0	100.0	100.0
Cost of revenues:			
Electricity Segment	63.6	58.4	56.5
Products Segment	69.7	74.6	76.7

	65.3	62.5	62.1
Gross margin:			
Electricity Segment	36.4	41.6	43.5
Products Segment	30.3	25.4	23.3
	34.7	37.5	37.9
Operating expenses (income):			
Research and development expenses	1.1	1.3	1.0
Selling and marketing expenses	3.9	3.3	3.5
General and administrative expenses	6.7	6.0	5.3
Gain on sale of geothermal resource rights	0.0	0.0	(0.4)
Operating income	23.0	26.9	28.5
Other income (expense):			
Interest income	2.4	1.8	0.6
Interest expense	(11.5)	(23.2)	(19.5)
Foreign currency translation and transaction loss	(0.3)	(0.2)	(0.1)
Other non-operating income	0.3	0.2	0.1
Income before income taxes, minority interest and equity in income of investees	14.0	5.5	9.6
Income tax provision	(2.4)	(2.0)	(3.0)
Minority interest in earnings of subsidiaries	(0.3)	0.0	(0.0)
Equity in income of investees	1.5	2.9	1.6
Net income	12.8%	6.4%	8.1%

Comparison of the Year Ended December 31, 2006 and the Year Ended December 31, 2005

Total Revenues

Total revenues for the year ended December 31, 2006 were $268.9 million, as compared with $238.0 million for the year ended December 31, 2005, which represented a 13.0% increase in total revenues. This increase is attributable both to our Electricity and Products Segments whose revenues increased by 10.2% and 21.2%, respectively, over the year ended December 31, 2005.

Electricity Segment

Revenues attributable to our Electricity Segment for the year ended December 31, 2006 were $195.5 million, as compared with $177.4 million for the year ended December 31, 2005, which represented a 10.2% increase in such revenues. This increase is primarily attributable to the following: (i) the consolidation of additional revenues in the amount of $10.3 million from the Zunil project, which was consolidated as of March 13, 2006; (ii) additional revenues of $5.9 million generated as a result of an increase in our generating capacity in the U.S. resulting in an increase in energy generation from 1,693,362 MWh in the year ended December 31, 2005 to 1,789,794 MWh in the year ended December 31 2006; and (iii) an increase of $1.3 million in lease income resulting from the Puna operating lease. We did not realize the aggregate generating capacity of our power plants in the year ended December 31, 2006 due to unexpected operational issues that we experienced in some of our plants, such as the Puna and Ormesa projects, and the delay in the commercial operation of the Desert Peak 2 plant.

Products Segment

Revenues attributable to our Products Segment for the year ended December 31, 2006 were $73.5 million, as compared with $60.6 million for the year ended December 31, 2005, which represented a 21.2% increase. This increase of $12.9 million in the year ended December 31, 2006 is principally attributable to increased sales of our geothermal and recovered energy generation products, which amounted to $68.8 million in the year ended December 31, 2006 as compared to $31.6 million, while sales of our remote power units decreased in the year ended December 31, 2006 following the completion of the large order received from the company developing the Sakhalin project in Russia which amounted to $18.9 million.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2006 was $175.6 million, as compared with $148.9 million for the year ended December 31, 2005, which represented an 18.0% increase in total cost of revenues. The increase in cost of revenues is partially due to the increase in revenues and partially attributable to increased costs in our Electricity Segment during the year ended December 31, 2006, as discussed below. As a percentage of total revenues, our total cost of revenues for the years ended December 31, 2006 and 2005 were 65.3% and 62.5%, respectively. The increase in cost of revenues as a percentage of total revenues is principally attributable to the increased costs in our Electricity Segment during the year ended December 31, 2006, which was partially offset by an increase in the profitability of our Products Segment during the year ended December 31, 2006. Total cost of revenues for the year ended December 31, 2006 includes stock-based compensation related to stock options of $0.8 million.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2006 was $124.4 million, as compared with $103.6 million for the year ended December 31, 2005, which represented a 20.0% increase in cost of revenues for such segment. This increase is primarily due to the following: (i) a $4.1 million cost of repairing two wells that experienced mechanical problems in the Puna project (we have incurred approximately $2.0 million in

additional repair costs in the first quarter of 2007); (ii) an increase of $5.8 million in depreciation and royalties as a result of additional generating capacity; (iii) an increase of $2.7 million in cost of revenues attributable to the Zunil project which was consolidated as of March 13, 2006; (iv) an increase in lease expense of $2.2 million resulting from the Puna operating lease; and (v) additional insurance costs of $1.9 million due to higher insurance premiums and additional premiums as a result of coverage of our additional assets. The remaining $4.1 million of the increase in our cost of revenues is attributable primarily to increased labor and materials costs in existing plants. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2006 was 63.6% compared with 58.4% for the year ended December 31, 2005.

Products Segment

Total cost of revenues attributable to our Products Segment for the year ended December 31, 2006 was $51.2 million, as compared with $45.2 million for the year ended December 31, 2005, which represented a 13.2% increase in total cost of revenues related to such segment. Such $6.0 million increase in total cost of revenues during the year ended

December 31, 2006 is attributable to the increase in our Products Segment revenues and a different product mix. As a percentage of total products revenues, our total cost of revenues attributable to our Products Segment for the year ended December 31, 2006 was 69.7% compared with 74.6% in the year ended December 31, 2005. Such 4.9% decrease was primarily attributable to the product mix.

Research and Development Expenses

Net research and development expenses for the year ended December 31, 2006 were $2.98 million, as compared with $3.04 million for the year ended December 31, 2005, which represented a 1.7% decrease in research and development expenses. Such decrease reflects fluctuations in the period in which actual expenses were incurred. Research and development expenses in the years ended December 31, 2006 and 2005 also include activity related to geothermal resource drillings. Grants received from the U.S. Department of Energy are offset against the related research and development expenses. Such grants amounted to $0.3 million and $1.3 million during the years ended December 31, 2006 and 2005, respectively.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2006 were $10.4 million, as compared with $7.9 million for the year ended December 31, 2005, which represented a 31.6% increase in selling and marketing expenses. The increase was due primarily to the increase in revenues in our Products Segment and an increase in personnel expenses and other administrative expenses as a result of the hiring of additional personnel to support our continued growth, and an increase in salaries. Selling and marketing expenses for the year ended December 31, 2006 constituted 3.9% of total revenues for such year, as compared with 3.3% for the year ended December 31, 2005. Such increase is principally attributable to an increase in personnel expenses and other administrative expenses, as described above, offset by the fixed cost nature of certain of our selling and marketing expenses against a larger total revenue base. Selling and marketing expenses for the year ended December 31, 2006 includes stock-based compensation related to stock options of $0.3 million.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2006 were $18.1 million, as compared with $14.3 million for the year ended December 31, 2005, which represented a 26.4% increase in general and administrative expenses. Such increase was primarily attributable to: (i) an increase in professional services fees, additional personnel expenses and other administrative expenses, all as a result of our initial implementation of internal controls and procedures required to comply with Section 404 of the Sarbanes-Oxley Act of 2002; (ii) an increase in personnel expenses and other administrative expenses as a result of the hiring of additional personnel to support our continued

growth and as a result of an increase in salaries; and (iii) an increase in insurance expenses of $0.6 million mainly related to political risk coverage of the Amatitlan project, which was under construction. General and administrative expenses for the year ended December 31, 2006 increased to 6.7% of total revenues for such period, from 6.0% for the year ended December 31, 2005. General and administrative expenses for the year ended December 31, 2006 includes stock-based compensation related to stock options of $0.6 million.

Interest Expense

Interest expense for the year ended December 31, 2006 was $31.0 million, as compared with $55.3 million for the year ended December 31, 2005, which represented a 44.0% decrease in such interest expense. The net decrease of $24.3 million was primarily due to a $16.6 million one-time charge relating to the early repayment of the Beal Bank loan, following the issuance of the OrCal Senior Secured Notes on December 8, 2005. Without the impact of the one-time charge, interest expense decreased by $7.7 million, which resulted from: (i) an increase of $4.6 million in interest capitalized to projects due to the higher volume of construction in this year compared with last year; (ii) a decrease of $2.3 million in interest expense to our parent; (iii) a decrease of $2.9 million in interest expense due to the refinancing of the Beal Bank loan with the OrCal Senior Secured Notes at a lower interest rate as described above; and (iv) a decrease of $0.6 million in interest expense in respect of the OFC Senior Secured Notes due to principal repayments. The decrease in interest expense was partially offset by an increase of $1.8 million in interest expense for the year ended December 31, 2006 attributable to the consolidation of interest expense from the Zunil project, which was consolidated as of March 13, 2006, and by a decrease of $0.6 million for the year ended December 31, 2006, in the fair value of interest rate caps, which as of December 8, 2005 are no longer qualified for hedge accounting due to the repayment of the Beal Bank loan.

Income Taxes

Income taxes for the year ended December 31, 2006 were $6.4 million, as compared with $4.7 million for the year ended December 31, 2005. The effective tax rates for the years ended December 31, 2006 and 2005 were 17.1% and 36.2%, respectively. Our effective tax rate decreased in the year ended December 31, 2006 compared with the year ended December 31, 2005 due to: (i) a production tax credit of $4.7 million in respect of our Burdette, Gould and Desert Peak 2 projects; (ii) the absence of income tax expense in respect of our Zunil project, due to our utilization of a tax credit in the amount of $1.1 million; (iii) a decrease of 3% in the tax rate in Israel commencing January 1, 2006, which decreased the tax provision by $0.5 million; and (iv) an Israeli Investment Law amendment and the resulting ruling from the Israeli Tax Authorities granted in April 2006 to Ormat Systems according to which Ormat Systems was subject to lower income tax rates effective as of January 1, 2004, which resulted in a tax benefit of $1.0 million.

Equity in Income of Investees

Our participation in the income generated from our investees for the year ended December 31, 2006 was $4.1 million, as compared with $6.9 million for the year ended December 31, 2005. Such decrease of $2.8 million was due to our 50% equity interest in the Mammoth project, whose revenues decreased because of lower generation as a result of temperatures higher than the average for the summer season and whose cost of revenues increased mainly as a result of unplanned major maintenance. In addition, the decrease in our equity in income of investees was attributable to the shutdown of the Zunil project in the first quarter of 2006, due to damage from a hurricane and the consolidation of Orzunil as of March 13, 2006, which decreased our equity income of investees by $0.7 million.

Net Income

Net income for the year ended December 31, 2006 was $34.4 million, as compared with $15.2 million for the year ended December 31, 2005, which represented an increase of 127.0% in our net income. Net income as a percentage of our total revenues for the year ended December 31, 2006

was 12.8%, as compared with 6.4% for the year ended December 31, 2005. Such increase in net income was principally attributable to: (i) a $16.6 million ($10.3 million after-tax) impact of the one-time charge from the repayment of the Beal Bank loan in the year ended December 31, 2005; (ii) a $4.2 million increase in gross margin primarily due to the increase in total revenues; and (iii) a decrease in our net interest expense of $10.0 million, offset by: (i) a decrease of $2.8 million in equity in income of investees; (ii) a $6.2 million increase in operating expenses; (iii) a $1.7 million increase in our income tax provision; and (iv) a $0.8 increase in minority interest in earnings of subsidiaries, due to the consolidation of the Zunil project. Net income for the year ended December 31, 2006 includes stock-based compensation related to stock options of $1.5 million.

Comparison of the Year Ended December 31, 2005 and the Year Ended December 31, 2004

Total Revenues

Total revenues for the year ended December 31, 2005 were $238.0 million, as compared with $219.2 million for the year ended December 31, 2004, which represented an 8.6% increase in total revenues. This increase is attributable primarily to the growth of our Electricity Segment, whose revenues in the year ended December 31, 2005 increased by 11.7% over the year ended December 31, 2004.

Electricity Segment

	Year Ended December 31,	
	2005	2004
	(in millions)	
Steamboat Project	$ 17.6	$ 15.4
Puna Project	36.2	15.5
Steamboat Hills Project	4.2	1.8
Other Projects	119.4	126.1
Total	$ 177.4	$ 158.8

Revenues attributable to our Electricity Segment for the year ended December 31, 2005 were $177.4 million, as compared with $158.8 million for the year ended December 31, 2004, which represented an 11.7% increase in such revenues. This increase is primarily attributable to the inclusion for a full year of the additional revenues being generated from the Steamboat 2/3 project, which we acquired on February 11, 2004, the Steamboat Hills project, which we acquired on May 20, 2004, and the Puna project, which we acquired on June 3, 2004. In addition, revenues from the Puna project in the year ended December 31, 2005 increased by $5.2 million due to higher energy rates, by $1.1 million due to increased generating capacity and by $1.4 million due to lease income resulting from the Puna operating lease. The decrease in revenues from Other Projects is primarily due to the deconsolidation of the Leyte project as of April 1, 2004, which represented $3.1 million of our revenues in the first quarter of 2004, a $3.1 million decrease due to lower availability of the well field at the Ormesa project and a $1.9 million decrease in the Heber project primarily due to our increased use of the power generated by the project for auxiliary purposes rather than purchasing this power from a third party, and a decrease in the ‘‘adder’’, an additional energy rate, paid under the Heber 2 power purchase agreement.

Products Segment

Revenues attributable to our Products Segment for the year ended December 31, 2005 were $60.6 million, as compared with $60.4 million for the year ended December 31, 2004, which represented a 0.4% increase in such revenues. The portion of our Products Segment revenues attributable to the supply of remote power units increased in

the year ended December 31, 2005 due to a large order from the Sakhalin project, which amounted to $18.9 million. In the year ended December 31, 2004, a significant portion of our Products Segment revenues was attributable to two large geothermal projects in New Zealand, which amounted to $49.5 million. The revenues from those projects in the year ended December 31, 2005 amounted to $10.6 million.

Total Cost of Revenues

Total cost of revenues for the year ended December 31, 2005 was $148.9 million, as compared with $136.1 million for the year ended December 31, 2004, which represented a 9.4% increase in total cost of revenues. As a percentage of total revenues, our total cost of revenues for the years ended December 31, 2005 and December 31, 2004 were 62.5% and 62.1%, respectively. The increase is principally attributable to increased costs in our Electricity Segment during the year ended December 31, 2005.

Electricity Segment

Total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2005 was $103.6 million, as compared with $89.7 million for the year ended December 31, 2004, which represented a 15.5% increase in cost of revenues for such segment. This increase is primarily due to the inclusion for a full year of the additional costs of revenues attributable to the Steamboat 1/1A and Steamboat 2/3 project (we acquired the Steamboat 2/3 project on February 11, 2004), the Steamboat Hills project (which we acquired on May 20, 2004) and the Puna project (which we acquired on June 3, 2004) for the year ended December 31, 2005 were $9.8 million, $3.0 million and $17.0 million, respectively, as compared with $7.7 million, $2.0 million and $6.6 million, respectively, for the year ended December 31, 2004. The remainder of the increase is mainly due to the increased costs in the amount of $3.0 million within the Ormesa project due to a significant increase in the geothermal field costs and maintenance costs of such project due to a higher-than-average rate of failure of production pumps and wells (including abandonment of one production well), which resulted in a lower availability of the well field. These costs included the replacement of a relatively large number of pumps and injection pipeline repairs. We also had increased costs in the amount of $0.8 million in the Steamboat project. The increase in total cost of revenues in our Electricity Segment was partially offset by the cancellation of accruals in the aggregate amount of $2.5 million due to the resolution of contingencies. As a percentage of total electricity revenues, the total cost of revenues attributable to our Electricity Segment for the year ended December 31, 2005 (58.4%) was higher than the percentage for the year ended December 31, 2004 (56.5%). Such increase is due in part to a lease expense in the amount of $3.1 million in the Puna project from May 19, 2005 to December 31, 2005. The increase is also attributable to the deconsolidation of the Leyte project as of April 1, 2004, whose total cost of revenues as a percentage of the project’s revenues in 2004 was 46.3%, which is lower than the average cost of revenues for this segment.

Products Segment

Total cost of revenues attributable to our Products Segment for the year ended December 31, 2005 was $45.2 million, as compared with $46.3 million for the year ended December 31, 2004, which represented a 2.4% decrease in cost of revenues related to such segment. Such $1.1 million decrease in cost of revenues during the year ended December 31, 2005 resulted from a different product mix. As a percentage of total products revenues, our total cost of revenues attributable to our Products Segment for the year ended December 31, 2005 was 74.6% and for the year ended December 31, 2004 was 76.7%.

Research and Development Expenses

Net research and development expenses for the year ended December 31, 2005 were $3.0 million, as compared with $2.2 million for the year ended December 31, 2004, which represented a 39.6% increase in research and development expenses. Such increase reflects fluctuations in the period in which actual expenses were incurred and includes also an increase in activity related to geothermal resource drillings. Grants received from the U.S. Department of Energy are offset against the related research and development expenses. Such grants amounted to $1.3 million and $0.1 million during the years ended December 31, 2005 and 2004, respectively.

Selling and Marketing Expenses

Selling and marketing expenses for the year ended December 31, 2005 were $7.9 million, as compared with $7.8 million for the year ended December 31, 2004. Selling and marketing expenses for

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the year ended December 31, 2005 constituted 3.3% of total revenues for such year, as compared with 3.5% for the year ended December 31, 2004. Such decrease is principally attributable to the fixed cost nature of certain of our selling and marketing expenses against a larger total revenue base.

General and Administrative Expenses

General and administrative exenses for the year ended December 31, 2005 were $14.3 million, as compared with $11.6 million for the year ended December 31, 2004, which represented a 23.4% increase in general and administrative expenses. Such increase was principally attributable to an increase in professional services fees, additional personnel expenses and other administrative expenses, all as a result of being a public company whose shares are traded on the New York Stock Exchange. General and administrative expenses for the year ended December 31, 2005 constituted 6.0% of total revenues for such period, as compared with 5.3% for the year ended December 31, 2004. In addition, the general and administrative expenses for the year ended December 31, 2004 did not fully reflect the increase in such expenses that was required as a result of the increased activity that occurred in connection with the acquisitions made in 2004.

Interest Expense

Interest expense for the year ended December 31, 2005 was $55.3 million, as compared with $42.8 million for the year ended December 31, 2004, which represented a 29.3% increase in such interest expense. The net increase of $12.5 million was primarily due to a $16.6 million one-time charge relating to the early repayment of the Beal Bank loan, which followed the issuance of the OrCal Senior Secured Notes. The charge is comprised of an $11.5 million prepayment premium, a $4.2 million write-off of deferred financing costs and a $0.9 million loss from a hedge transaction previously included in other comprehensive loss. Without the impact of the one-time charge, interest expense decreased by $4.1 million, which resulted from (i) $3.5 million in interest capitalized to projects due to a higher volume of construction as compared with $0.6 million last year, (ii) a decrease in interest expenses of $2.2 million as a result of the repayment of the Ormesa loan on December 31, 2004, (iii) the payment of an interest expense of $1.6 million for the year ended December 31, 2004 related to the decrease in the fair value of the interest rate caps in respect of the Beal Bank financing; beginning in October 2004 the caps qualified for hedge accounting under SFAS No. 133, and as such we have recorded the decrease in the value of the caps in respect of such transactions in other

comprehensive income. As a result of the repayment of the Beal Bank loan on December 8, 2005, these caps are no longer qualified for hedge accounting and for the period from December 8, 2005 to December 31, 2005, $0.3 million were included in interest expense related to the decrease in the fair value for such period. In addition, the decrease in the fair value from October 1, 2004 to December 8, 2005 in the amount of $0.9 million was included in the prepayment charge as described above, and (iv) the elimination of interest expenses of the loan from Export-Import Bank used to finance the Leyte project in the amount of $0.2 million as a result of the deconsolidation of the Leyte project in April 1, 2004 (as a result of the application of FIN No. 46R). Such decreases were offset by: a $1.9 million increase in interest expense in respect of the $190.0 million of the OFC Senior Secured Notes, a $0.9 million increase in interest payments to our parent, and a $0.8 million increase in the applicable LIBOR rate for the Beal Bank financing.

Income Taxes

Income taxes for the year ended December 31, 2005 were $4.7 million, as compared with $6.6 million for the year ended December 31, 2004. The effective tax rates for the years ended December 31, 2005 and 2004 were 36.2% and 31.6%, respectively. Our effective tax rate increased in the year ended December 31, 2005 compared with the year ended December 31, 2004 primarily due to utilization of carry-forward tax losses in Israel during the first half of 2004, for which a full valuation allowance has been recorded against deferred tax assets. No investment tax credit or production tax credits were claimed in the years ended December 31, 2005 and 2004.

During the year ended December 31, 2005, Ormat Momotombo Power Company paid the total amount of approximately $1,700 in tax penalties, due mainly to the late filings of tax withholding reports.

Equity in Income of Investees

Our participation in the income generated from our investees for the year ended December 31, 2005 was $6.9 million, as compared with $3.6 million for the year ended December 31, 2004, which represented a 93.3% increase. Such increase was principally attributable to the income generated in connection with our 80% equity interest in the Leyte project, which was deconsolidated as of April 1, 2004 (as a result of the application of FIN No. 46R), which accounted for $4.9 million, and our collection of an insurance claim, that had not been insured until collected, related to that project in the second quarter of 2005. In the third quarter of 2004, the Leyte Project had a net loss as a result of equipment damage, which was recovered by insurance payments in the fourth quarter of 2004 and the second quarter of 2005.

Net Income

Net income for the year ended December 31, 2005 was $15.2 million, as compared with $17.8 million for the year ended December 31, 2004. Net income as a percentage of our total revenues for the year ended December 31, 2005 was 6.4%, as compared with 8.1% for the year ended December 31, 2004. The $2.6 million decrease in net income and the decrease in net income as a percentage of our total revenues were due to a $10.3 million after-tax impact of the one-time charge from the repayment of the Beal Bank loan. The impact of the prepayment charge was partially offset by an increase in net income principally attributable to: (i) a $6.0 million increase in gross margin, (ii) a decrease in our net interest expense of $7.1 million, (iii) a $1.9 million decrease in our income tax provision, and (iv) an increase of $3.3 million in equity in income of investees, offset by a $4.5 million increase in operating expenses.

Net income excluding the after-tax impact of the prepayment charge was $25.5 million, an increase of $7.7 million or 43.2% compared with the net income for the year ended December 31, 2004.

Stock-based Compensation

Effective January 1, 2006, we adopted SFAS No. 123(R), Share-Based Payments, (SFAS No. 123R), which establishes the accounting for employee stock-based awards. Under the provisions of SFAS No. 123R, stock-based compensation 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). We adopted SFAS No. 123R using the modified prospective method. Under this method, prior periods are not restated and the amount of compensation cost recognized includes (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, and (ii) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior to January 1, 2006, we accounted for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion No. 25 (APB No. 25), Accounting for Stock Issued to Employees, and related interpretations. Under APB No. 25, compensation cost was recognized based on the difference, if any, on the date of grant between the fair value of our common stock and the amount an employee must pay to acquire the stock.

During the year ended December 31, 2006, we recognized net stock-based compensation expenses related to stock options of $1.5 million. As of December 31, 2006, the unrecorded deferred stock-based compensation balance related to stock options was $3.7 million and will be recognized over an estimated weighted average amortization period of 3.4 years.

Liquidity and Capital Resources

To date, our principal sources of liquidity have been derived from cash from operations, proceeds from parent company loans, third party debt in the form of borrowing under credit facilities, issuance by Ormat Funding and OrCal Geothermal of their Senior Secured Notes, project financing (including lease) and the issuance of our common stock in public offerings. We have utilized this cash to fund

our acquisitions, develop and construct power generation plants and meet our other cash and liquidity needs. Our management believes that the outstanding cash, cash equivalents, marketable securities and cash generated from our operations will address our liquidity and other investment requirements. In addition, our shelf registration statement on Form S-3, which was declared effective on January 31, 2006, provides us with the ability to raise additional capital through the issuance of securities pursuant to the terms and conditions of the shelf registration. As described below, since the capital note in the amount of $50.7 million with our parent is payable upon demand at any time after November 30, 2007, it is presented in our balance sheet as of December 31, 2006 in current liabilities.

Loan Agreements with our Parent

In 2003, we entered into a loan agreement with Ormat Industries Ltd. (our parent company), which was further amended on September 20, 2004. Pursuant to this loan agreement, Ormat Industries agreed to make a loan to us in one or more advances not exceeding a total aggregate amount of $150.0 million. The proceeds of the loan are to be used to

fund our general corporate activities and investments. We are required to repay the loan and accrued interest in full and in accordance with an agreed-upon repayment schedule and in any event on or prior to June 5, 2010. Interest on the loan is calculated on the balance from the date of the receipt of each advance until the date of payment thereof at a rate per annum equal to Ormat Industries' average effective cost of funds plus 0.3% in dollars, which represented a rate of 7.5% for the advances made during 2003. All computations of interest shall be made by Ormat Industries on the basis of a year consisting of 360 days. As of December 31, 2006, the outstanding balance of the loan was approximately $89.5 million compared to $121.1 million as of December 31, 2005.

In addition to the above loan, pursuant to the terms of a capital note, as amended on September 20, 2004, Ormat Industries converted outstanding balances owed by us to Ormat Industries into a subordinated non-interest bearing loan in an amount equal to New Israeli Shekels (NIS) 240.0 million. At any time after November 30, 2007 upon demand by Ormat Industries, we will be required to repay the loan in full. The final maturity of the loan is December 30, 2009. In accordance with the terms of such note, we will not be required to repay any amount in excess of $50.7 million (using the exchange rate existing on the date of such note). As of December 31, 2006 and 2005 the ceiling of $50.7 million is effective. Since the note is payable upon demand at any time after November 30, 2007 it is presented in our balance sheet as of December 31, 2006 in current liabilities.

Third Party Debt

Our third-party debt is composed of two principal categories. The first category consists of project finance debt or acquisition financing that we or our subsidiaries have incurred for the purpose of developing and constructing, refinancing or acquiring our various projects. The second category consists of debt incurred by us or our subsidiaries for general corporate purposes.

OrCal Geothermal Senior Secured Notes — Non-Recourse

On December 8, 2005, OrCal Geothermal Inc (OrCal), one of our subsidiaries, issued $165.0 million, 6.21% Senior Secured Notes (OrCal Senior Secured Notes) in an offering subject to Rule 144A and Regulation S of the Securities Act of 1933, as amended, for the purpose of refinancing the acquisition cost of the Heber projects. The OrCal Senior Secured Notes have been rated BBB− by Fitch. 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 that commenced on June 30, 2006. The OrCal Senior Secured Notes are collateralized by substantially all of the assets of OrCal and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OrCal. There are various restrictive covenants under the OrCal Senior Secured Notes, which include limitations on additional indebtedness and payment of dividends. As of December 31, 2006, we were in compliance with the covenants under the OrCal Senior Secured Notes.

The proceeds from this issuance were used to prepay in full OrCal's outstanding loan with Beal Bank and to pay for transaction costs. As a result of the prepayment of the Beal Bank loan, we

recorded in the fourth quarter of 2005 a net charge of approximately $10.3 million, net of related taxes of approximately $6.3 million. As of December 31, 2006, there were $160.7 million of OrCal Senior Secured Notes outstanding.

Ormat Funding Senior Secured Notes — Non-Recourse

On February 13, 2004, Ormat Funding Corp. (OFC), one of our subsidiaries, issued $190.0 million, 8¼% Senior Secured Notes (OFC Senior Secured Notes) in an offering subject to Rule 144A and Regulation S of the Securities Act of 1933, as amended, for the purpose of refinancing the acquisition cost of the Brady, Ormesa and Steamboat 1/1A projects, and the financing of the acquisition cost of the Steamboat 2/3 project. The OFC Senior Secured Notes have a final maturity date of December 30, 2020. Principal and interest on the OFC Senior Secured Notes are payable in semi-annual payments that commenced on June 30, 2004. The OFC Senior Secured Notes are collateralized by substantially all of the assets of Ormat Funding and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC. There are various restrictive covenants under the OFC Senior Secured Notes, which include limitations on additional indebtedness and payment of dividends. On June 30 and December 31, 2006, OFC did not meet the ‘‘debt service coverage ratio’’ and therefore it was restricted from payment of dividends until it meets such ratio. As of December 31, 2006, there were $178.7 million of OFC Senior Secured Notes outstanding.

We have not yet granted a security interest over the new unit of the Desert Peak 2 project to the OFC Senior Secured Noteholders which is required under the indenture for the OFC Senior Secured Notes. We are evaluating an alternative approach to replacing the Desert Peak 1 plant with one of the new units of the Desert Peak 2 project. Implementing such an alternative would require the consent of the OFC Senior Secured Noteholders in order to ensure continued compliance with the covenants of the indenture governing the OFC Senior Secured Notes. We expect to launch a consent solicitation in order to amend and/or waive certain provisions of the indenture to obtain such consent from the OFC Senior Secured Noteholders. Any such solicitation will be made by means of and subject to appropriate documentation and only to the OFC Senior Secured Noteholders.

A registration statement on Form S-4 relating to the OFC Senior Secured Notes was filed with and declared effective by the SEC on February 9, 2005. On March 16, 2005, we exchanged these unregistered notes for senior secured notes with substantially identical terms that have been registered under the Securities Act of 1933, as amended.

On April 26, 2006, OFC successfully consummated a consent solicitation relating to the OFC Senior Secured Notes that was launched on April 17, 2006. On that same date, OFC executed a supplement to the Indenture governing the OFC Senior Secured Notes to amend and/or waive certain provisions in the indenture dealing with public reporting and information requirements of OFC. On May 1, 2006, OFC filed with the SEC a Form 15 notification of the suspension of its obligation to file reports with the SEC under the Securities Act of 1934.

Senior Loans from International Finance Corporation (IFC) and Commonwealth Development Corporation (CDC) — Non-Recourse

Orzunil, a wholly owned subsidiary which was consolidated as of March 13, 2006, has senior loan agreements with IFC and CDC, which were minority shareholders of Orzunil (see ‘‘Recent Developments’’ regarding our acquisition of the minority interest in Orzunil). The first loan from IFC, of which $7.0 million was outstanding as of December 31, 2006, has a fixed annual interest rate of 11.775%, and matures on November 15, 2011. The second loan from IFC, of which $3.9 million was outstanding as of December 31, 2006, has a fixed annual interest rate of 11.730%, and matures on May 15, 2008. The loan from CDC, of which $8.5 million was outstanding as of December 31, 2006, has a fixed annual interest rate of 10.3%, and matures on August 15, 2010. There are various restrictive covenants under the Senior Loans, which include limitations on Orzunil’s ability to make distributions to its shareholders.

Due to hurricane activity, access roads and piping from the wells to the power plant in the Zunil Project were damaged and as a result, the Project was not in operation from October 14, 2005 to

March 10, 2006. As a result, Orzunil did not meet the historical ‘‘debt service coverage ratio’’ required and therefore distributions from the Project are restricted. Currently, Orzunil is in compliance with the required debt service coverage ratio and with all other covenants.

Other Limited and Non-Recourse Debt

The Bank Hapoalim project finance debt, of which $11.3 million was outstanding as of December 31, 2006, bearing an interest rate of 3-month LIBOR plus 2.375% per annum on tranche one of the loan and 3-month LIBOR plus 3.0% per annum on tranche two of the loan, and the Export-Import Bank of the United States project finance debt, of which $3.8 million was outstanding as of December 31, 2006, bearing an interest rate of 6.54% per annum, were entered into by our relevant subsidiaries to finance the Momotombo project and the Leyte project (which was deconsolidated as of April 1, 2004), respectively.

Our management believes that we are currently in compliance with our covenants with respect to our third-party debt, except as described above regarding the OFC Senior Secured Notes and the Orzunil Senior Loans.

New Financing of our Projects

Financing of the Amatitlan Project

Currently, we intend to refinance our equity investment in the construction cost of the Amatitlan project during the third quarter of 2007. In connection with such refinancing, we signed a mandate letter with a local bank in Guatemala containing proposed terms for a construction loan with a term of up to two years and a 10-year term loan in the total amount of approximately $41.0 million.

Financing of Phase II of Olkaria III Project

We have engaged a financial institution and received an indicative proposal to arrange long-term financing for the Olkaria III project. We expect negotiations and preparation of loan documentation to follow shortly.

Full-Recourse Debt

Our full-recourse third party debt includes an $8 million medium term loan from Bank Hapoalim, of which $2.0 million was outstanding as of December 31, 2006, bearing an interest rate of 12-month LIBOR plus 1.7% per annum.

In connection with our acquisition through Ormat Systems Ltd. of the power generation business from our parent, we entered into certain agreements with various banks, of which only those with each of Bank Hapoalim, Bank Leumi and Mizrahi Tefahot Bank remain. Under these agreements, in exchange for such banks’ release of our parent’s guarantee and a release of their security interest over the assets of our subsidiary, Ormat Systems, we and Ormat Systems have agreed to certain negative covenants, including, but not limited to, 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. In some cases, we and Ormat Systems have agreed to maintain certain financial ratios such as a debt service coverage ratio and a debt to equity ratio. We do not expect that these covenants or ratios, which apply to us on a consolidated basis, will materially limit our ability to execute our future business plans or our operations. 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.

We do not expect that any third party debt that we, or any of our subsidiaries, will incur in the future will be guaranteed by our parent.

Most of the loan agreements to which we or our subsidiaries are a party contain cross-default provisions with respect to other material indebtedness owed by us to any third party.

On February 15, 2006, our subsidiary, Ormat Nevada, entered into a $25.0 million credit agreement with Union Bank of California (UBOC). Under the credit agreement, Ormat Nevada can request extensions of credit in the form of loans and/or the issuance of one or more letters of credit. UBOC 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 have 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 by any of its (or any of its subsidiaries') assets.

Loans and draws under the letters of credit (if any) under the credit agreement will bear interest at the floating rate based on the Eurodollar plus a margin. There are various restrictive covenants under the credit agreement, which include maintaining certain levels of tangible net worth, leverage ratio, minimum coverage ratio, and a distribution coverage ratio. In addition, there are restrictions on dividend distributions in the event of a payment default or noncompliance with such ratios.

As of December 31, 2006, three letters of credit, with an aggregate stated amount of $21.9 million, have been issued and are outstanding under this credit agreement with UBOC.

Our management believes that we are currently in compliance with our covenants with respect to our third-party debt, except as described above regarding the OFC Senior Secured Notes and the Orzunil Senior Loans.

Letters of Credit and Off-balance Sheet Arrangements

As described above under ''Full Recourse Debt'', on February 15, 2006, our subsidiary Ormat Nevada, entered into a credit agreement with Union Bank of California.

On June 30, 2004, our subsidiary, Ormat Nevada, entered into a Letter of Credit Agreement with Hudson United Bank, pursuant to which Hudson United Bank agreed to issue one or more letters of credit in an aggregate face amount of up to $15.0 million. Under this Letter of Credit Agreement in the event that the bank is required to pay on a letter of credit drawn by the beneficiary thereof, such letter of credit converts to a loan, bearing interest at one-month LIBOR plus 4.0%, and matures on the next expiration date of the Letter of Credit Agreement. There are various restrictive covenants under the Letter of Credit Agreement, which include maintaining certain levels of tangible net worth, leverage ratio, and minimum coverage ratio. Some of our customers require our project subsidiaries to post letters of credit in order to guarantee their respective performance under relevant contracts. We are also required to post letters of credit to secure our obligations under various leases and licenses and may, from time to time, decide to

post letters of credit in lieu of cash deposits in reserve accounts under certain financing arrangements. In addition, our subsidiary, Ormat Systems, is required from time to time to post performance letters of credit in favor of our customers with respect to orders of products. As of December 31, 2006 and 2005, no letters of credit were outstanding under the Letter of Credit Agreement.

Bank Leumi and Bank Hapoalim have issued such performance letters of credit in favor of our customers from time to time. Initially, our parent, Ormat Industries, was the obligor in respect of any reimbursement obligation on such letters of credit and we paid our parent a guarantee fee and were responsible to reimburse our parent for any draw under these letters of credit. In connection with the acquisition transaction of the power generation business by Ormat Systems from our parent, we have assumed such letters of credit and are now the direct obligor of Bank Leumi and Bank Hapoalim on such letters of credit. As of December 31, 2006, Bank Leumi and Bank Hapoalim have agreed to make available to us letters of credit totaling $25.6 million and $7.9 million, respectively. As of such date, Bank Leumi and Bank Hapoalim have issued letters of credit in the amount of $10.7 million and $6.6 million, respectively.

As of the date hereof, we have not had a draw presented against any letter of credit issued or provided on our behalf.

Puna Project Lease Transactions

On May 19, 2005, our subsidiary in Hawaii, Puna Geothermal Ventures (PGV), entered into a transaction involving the Puna geothermal power plant located on the Big Island of Hawaii. The transaction was concluded with financing parties by means of a leveraged lease transaction. A secondary stage of the lease transaction relating to two new geothermal wells that PGV drilled in the second half of 2005 (for production and injection) was completed on December 30, 2005. Pursuant to a 31-year head lease, PGV leased its geothermal power plant to the abovementioned financing parties in return for a deferred lease income in the amount of $83.0 million. Transaction costs amounted to $4.3 million. The proceeds from the transactions are being used for future capital expenditures and for general corporate purposes.

Dividend

The following are the dividends we declared during the past two years:

Date Declared	Dividend Amount per Share	Record Date	Payment Date
March 22, 2005	$ 0.03	April 4, 2005	April 18, 2005
May 10, 2005	$ 0.03	May 23, 2005	June 6, 2005
August 11, 2005	$ 0.03	August 22, 2005	September 1, 2005
November 9, 2005	$ 0.03	November 29, 2005	December 6, 2005
March 7, 2006	$ 0.03	March 28, 2006	April 4, 2006
May 9, 2006	$ 0.04	May 23, 2006	May 30, 2006
August 6, 2006	$ 0.04	August 23, 2006	August 30, 2006
November 7, 2006	$ 0.04	November 30, 2006	December 13, 2006

February 27, 2007	$ 0.07	March 21, 2007	March 29, 2007

Historical Cash Flows

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

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Net cash provided by operating activities	$ 73,035	$ 134,938	$ 63,458
Net cash used in investing activities	(249,147)	(83,408)	(310,583)
Net cash provided by (used in) financing activities	169,390	(61,304)	275,002
Net increase (decrease) in cash and cash equivalents	(6,722)	(9,774)	27,877

For the Year Ended December 31, 2006

Net cash provided by operating activities for the year ended December 31, 2006 was $73.0 million, as compared with net cash provided by operating activities of $134.9 million for the year ended December 31, 2005. Such net decrease of $61.9 million resulted primarily from: (i) the increase in net income from $15.2 million to $34.4 million as a result of additional revenues being generated from the increase of our generating capacity in the United States and from the Zunil project which was consolidated as of March 13, 2006; (ii) the prepaid lease payment of $83.0 million in the year ended December 31, 2005 pursuant to the leverage lease transaction of the Puna project (less $3.3 million deferred costs related to such lease transaction); and (iii) an increase of $12.1 million in accounts payable and accrued expenses for the year ended December 31, 2006 as compared with an increase of $7.2 million for the year ended December 31, 2005 mainly due to interest accrued on the OFC and OrCal Senior Secured Notes (which was paid on January 2, 2007), offset by a decrease in trade payables as a result of the timing of payments to suppliers and service providers.

Net cash used in investing activities for the year ended December 31, 2006 was $249.1 million, as compared with $83.4 million used in investing activities for the year ended December 31, 2005. The principal factors that affected our cash flow used in investing activities during the year ended December 31, 2006 were: (i) capital expenditures of $159.5 million utilized primarily for our power facilities under construction; (ii) $22.8 million used in the acquisition of an additional 79% of the Zunil project in Guatemala; and (iii) a net increase of $52.7 million in our investment of excess cash in marketable securities.

Net cash provided by financing activities for the year ended December 31, 2006 was $169.4 million, as compared with $61.3 million used in financing activities for the year ended December 31, 2005. The principal factors that affected the cash flow used in financing activities during the year ended December 31, 2006 were the receipt of proceeds from the follow-on offering of $135.1 million and the $92.4 million net proceeds from our sale of shares in a block trade, offset by: (i) the repayment of short-term and long-term debt in the amount of $20.7 million, (ii) the repayment of debt to our parent in the amount of $31.6 million; and (iii) the payment of a dividend to our shareholders in the amount of $5.2 million.

For the Year Ended December 31, 2005

Net cash provided by operating activities for the year ended December 31, 2005 was $134.9 million, as compared with net cash provided by operating activities of $63.5 million for the year ended December 31, 2004. Such net increase of $71.5 million resulted primarily from a prepaid lease payment of $83.0 million pursuant to the leverage lease transaction of Puna (less $3.3 million transaction costs related to such lease transaction) offset mainly by a decrease of $2.6 million in net income due to the prepayment charge relating to the Beal Bank Loan, net of an increase in the operating activities as a result of the inclusion for a full year of the additional revenues being generated from the Steamboat 2/3 project, which we acquired on February 11, 2004, the Steamboat Hills project, which we acquired on May 20, 2004, and the Puna project, which we acquired on June 3, 2004.

Net cash used in investing activities for the year ended December 31, 2005 was $83.4 million, as compared with $310.6 million used in investing activities for the year ended December 31, 2004. The principal factor that affected our cash flow used in investing activities during the year ended December 31, 2005 was capital expenditures of $116.7 million primarily for our power facilities under construction. Such cash used in investing activities was offset by a decrease of $45.6 million in marketable securities of which $13.7 million was allocated to restricted cash.

Net cash used in financing activities for the year ended December 31, 2005 was $61.3 million, as compared with $275.0 million provided by financing activities for the year ended December 31, 2004. The principal factors that affected the cash flow used in financing activities during the year ended December 31, 2005 were the repayment of short-term and long-term debt in the amount of $184.0 million (including the Beal Bank loan), repayment of debt to our parent in the amount of $40.2 million, and the payment of a dividend to our shareholders in the amount of $6.3 million. This decrease was partially offset by the $165.0 million in proceeds (less $3.9 million in debt issuance costs) from the issuance of OrCal Senior Secured Notes, which were used to repay the Beal Bank loan.

Capital Expenditures

Our capital expenditures primarily relate to two principal components: the enhancement of our existing power plants and the construction and development of new power plants. In addition, we have budgeted approximately $16.0 million for the next two years for investment in buildings, machinery and equipment, including drilling equipment.

To the extent not otherwise described below, we expect that the following enhancements of our existing power plants and the construction of new power plants will be funded initially from internally generated cash or other available corporate resources, which we expect to subsequently refinance with limited or non-recourse debt at the project level. We currently do not contemplate obtaining any new loans from our parent company.

Amatitlan Project. We completed the construction of the Amatitlan project, and expect to declare commercial operation in the first half of 2007.

Ormesa Project. We completed the drilling of additional wells at the Ormesa project. We are in the process of adding additional OEC units, and increasing the output of the project by an estimated 10 MW. We estimate that such enhancements will be completed by the end of the first quarter of 2007. We are currently in negotiations with Southern California Edison for the sale of this additional estimated 10 MW.

Galena 2 Project (formerly Desert Peak 3 Project). We are in the final construction stage of the Galena 2 power plant in the Steamboat complex, which will supply electricity under the Galena 2 power purchase agreement. We estimate that the construction of the Galena 2 project will be completed in the first half of 2007.

Phase II of Olkaria III Project. In connection with Phase II of the Olkaria III project, we completed the drilling of the wells and have recently released the construction of the 35 MW power plant.

OrSumas Project. This recovered energy 5 MW project was scheduled to be completed in the last quarter of 2007 or the first quarter of 2008. The environmental issues identified in this project and described elsewhere in this report may delay or terminate its completion.

Steamboat Hills Project. We plan to add 5 MW to the Steamboat Hills project through the construction of OEC Units. Construction has been completed and the project is in its start up phase.

Puna Project. An enhancement program for the Puna project is currently planned and is intended to increase the output of the project by an estimated 8 MW through the construction of OEC Units. We expect that such enhancement program will be completed in 2008 and are currently negotiating the power purchase agreement for that addition.

Heber SouthProject (formerly Imperial Valley). We commenced construction of the Heber South project, a 10 MW power plant, which will be located in the Heber known geothermal resource area. The construction activity is expected to include the drilling of production and injection wells and the construction of an OEC unit. We expect the construction to be completed by the end of 2007 or the beginning of 2008.

Galena 3 Project. We are currently constructing the Galena 3 project, which will deliver 17 MW of power generation under a 20-year power purchase agreement with Sierra Pacific Power Company. We expect the construction to be completed by the end of 2007 or the beginning of 2008.

Brawley Phase I Project. We are currently constructing the Brawley Phase I project, which will deliver approximately 50 MW of power generation. We expect the construction to be completed by the end of 2008.

We have budgeted approximately $520 million through the end of 2008 for the above-described projects and have invested $150 million of such budget as of December 31, 2006.

In addition to the above projects, our operating projects have capital and expenditures budgets of approximately $16.7 million and we also plan to start other construction and enhancement of additional projects, including exploration work, for a total investment amount of approximately $17.0 million.

Other than the enhancements and new projects described above, and new projects that we may develop under new bids, we do not anticipate any other material capital expenditures in the near term for any of our operating projects, other than ordinary maintenance requirements and major maintenance, which we typically fund with internally generated cash.

Exposure to Market Risks

One market risk to which power plants are typically exposed is the volatility of electricity prices. However, our exposure to such market risk is currently limited because our long-term power purchase

agreements have fixed or escalating rate provisions that limit our exposure to changes in electricity prices. However, beginning in May 2012, the energy payments under the power purchase agreements of the Heber 1 and 2 projects, the Ormesa project and the Mammoth project will be determined by reference to the relevant power purchaser's short run avoided costs. The Puna project is currently benefiting from energy prices which are higher than the floor under the Puna power purchase agreement, as a result of the high fuel costs that impact Hawaii Electric Light Company's avoided costs. In addition, under certain of the power purchase agreements for our projects in Nevada, the price that Sierra Pacific Power Company pays for energy and capacity is based upon California-Oregon border power market pricing.

As of December 31, 2006, 97.4% of our consolidated long-term debt (including amounts owed to our parent) was in the form of fixed rate securities and therefore not subject to interest rate volatility risk. As of such date, 2.6% of our debt was in the form of a floating rate instrument, exposing us to changes in interest rates in connection therewith. As of December 31, 2006, $13.3 million of our debt remained subject to some floating rate risk. As such, our exposure to changes in interest rates with respect to our long-term obligations is immaterial.

Another market risk to which we are exposed is primarily related to potential adverse changes in foreign currency exchange rates, in particular the fluctuation of the U.S. dollar versus the new Israeli shekel (NIS). Risks attributable to fluctuations in currency exchange rates can arise when any of our foreign subsidiaries borrows funds or incurs operating or other expenses in one type of currency but receives 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. All of our power purchase agreements in the international markets are either U.S. dollar-denominated or linked to the U.S. dollar. Our construction contracts from time to time contemplate costs which are incurred in local currencies. The way we often mitigate such risk is to receive part of the proceeds from the sale contract in the currency in which the expenses are incurred. In the past, we have not used any material foreign currency exchange contracts or other derivative instruments to reduce our exposure to this risk. In the future, we may use such foreign currency exchange contracts and other derivative instruments to reduce our foreign currency exposure 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 currently maintain our surplus cash in short-term, interest-bearing bank deposits and auction rate securities, which we refer to as PARS (deposits of entities with a minimum investment grade rating of AA by Standard & Poor's Ratings Services).

Effects of Inflation

We do not expect that the low inflation environment of recent years in most of the countries in which we operate will continue. To address rising inflation, some of our contracts include certain mitigating factors against any inflation risk. In connection with the Electricity Segment, inflation may directly impact an expense incurred for the operation of our projects, hence increasing the overall operating cost to us. The negative impact of inflation may be partially offset by price adjustments built into some of our power purchase agreements that could be triggered upon such occurrences. Energy payments pursuant to the power purchase agreements for the Mammoth project (after April 2012), Ormesa project (after April 2012), Heber 1 and 2 projects (after April 2012) and Steamboat 1/1A project will change because of our power purchasers' underlying short run avoided costs. To the extent that inflation causes an increase in those short run avoided costs, higher energy payments could have an offsetting impact to any inflation-driven increase in our expenses. Similarly, the energy payments pursuant to the power purchase agreements for the Brady project,

Steamboat 2/3 project, the Steamboat Hills project and the Burdette project increase every year through the end of the relevant terms of such agreements, though such increases are not directly linked to the CPI. Lease

payments are generally fixed, while royalty payments are generally determined as a percentage of revenues and therefore are not significantly impacted by inflation.

Overall, we believe that the impact of inflation on our business will not be significant.

Contractual Obligations and Commercial Commitments

The following table sets forth our material contractual obligations as of December 31, 2006, excluding interest (in thousands):

		Payment of Principal Due By Period					
	Remaining Total	2007	2008	2009	2010	2011	Thereafter
Long-Term non-recourse and limited recourse debt	$ 30,639	$ 8,482	$ 7,667	$ 6,676	$ 6,101	$ 1,713	$ —
Long-Term recourse debt	2,000	1,000	1,000	—	—	—	—
Senior secured notes due 2020	339,370	40,054	25,476	20,183	20,334	21,110	212,213
Ormat Industries notes payable	140,153	82,312	31,641	16,600	9,600	—	—
Total	$ 512,162	$ 131,848	$ 65,784	$ 43,459	$ 36,035	$ 22,823	$ 212,213

The following table sets forth our interest payments payable in connection with our contractual obligations as of December 31, 2006 (in thousands):

		Payment of Interest Due By Period					
	Remaining Total	2007	2008	2009	2010	2011	Thereafter
Long-Term non-recourse and limited recourse debt	$ 6,575	$ 2,778	$ 1,905	$ 1,215	$ 548	$ 129	$ —
Long-Term recourse debt	216	144	72	—	—	—	—
Senior secured notes due 2020	187,871	35,730	21,554	19,924	18,483	16,997	75,183
Ormat Industries notes payable	10,977	5,982	3,549	716	730	—	—
Total	$ 205,639	$ 44,634	$ 27,080	$ 21,855	$ 19,761	$ 17,126	$ 75,183

Interest on the OFC Senior Secured Notes due in 2020 is fixed at a rate of 8.25%. Interest on the OrCal Senior Secured Notes due in 2020 is fixed at a rate of 6.21%. Interest on the Orzunil Senior Loans due in 2008, 2010 and

2011 is fixed at rates of 11.730%, 10.300% and 11.775%, respectively. Interest on Ormat Industries notes payable in the amount of $89.5 million is fixed at the rate of 7.50%, while a capital note in the amount of NIS 240 million ($50.7 million, using the exchange rate existing on the date of such note) is interest free. Interest on the remaining debt is variable (based primarily on changes in LIBOR rates). Accordingly, for purposes of the above calculation of interest payments pertaining to variable rate debt, the methodology used to determine future LIBOR rates was the use of Constant Maturity Swaps.

The following table sets forth our future minimum lease payments under the Puna project's lease, as of December 31, 2006 (in thousands):

	Future Minimum Lease Payments Due By Period						
	Remaining Total	2007	2008	2009	2010	2011	Thereafter
Operating lease payments	$ 113,082	$ 9,742	$ 7,573	$ 8,013	$ 7,567	$ 8,061	$ 72,126

The following table sets forth our future payment of benefits to our employees in Israel upon their reaching normal retirement age, as of December 31, 2006 (in thousands):

	Benefit Payments Upon Retirement Due By Period						
	Remaining Total	2007	2008	2009	2010	2011	Thereafter
Benefits payments upon retirement	$ 7,126	$ 794	$ 624	$ 702	$ 42	$ 668	$ 4,296

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 us before reaching their normal retirement age.

Concentration of Credit Risk

Our credit risk is currently concentrated with a limited number of major customers: Sierra Pacific Power Company, Southern California Edison and Hawaii Electric Light Company. If any of these electric utilities fails to make payments under its power purchase agreements with us, such failure would have a material adverse impact on our financial condition.

Southern California Edison accounted for 30.0%, 36.1% and 41.4% of our total revenues for the three years ended December 31, 2006, 2005 and 2004, respectively. Southern California Edison is also the power purchaser and revenue source for our Mammoth project, which we account for separately under the equity method of accounting.

Sierra Pacific Power Company accounted for 12.8%, 14.1% and 12.9% of our total revenues for the three years ended December 31, 2006, 2005 and 2004, respectively.

Hawaii Electric Light Company accounted for 15.1%, 15.2% and 7.1% of our total revenues for the years ended December 31, 2006, 2005 and 2004, respectively.

Government Grants and Tax Benefits

The U.S. government encourages production of electricity from geothermal resources through certain tax subsidies. We are permitted to claim approximately 10% of the cost of each new geothermal power plant in the United States as an investment tax credit against our federal income taxes. Alternatively, we are permitted to claim a ‘‘production tax credit,’’ which in 2006 was 1.9 cents per kWh and which is adjusted annually for inflation. The production tax credit may be claimed on the electricity output of new geothermal power plants put into service by December 31, 2008. Credit may be claimed for ten years on the output from any new geothermal power plants put into service prior to December 31, 2008. The owner of the project must choose between the production tax credit and the 10% investment tax credit described above. In either case, under current tax rules, any unused tax credit has a 1-year carry back and a 20-year carry forward. Whether we claim the production tax credit or the investment credit, we are also permitted to depreciate most of the plant for tax purposes over five years on an accelerated basis, meaning that more of the cost maybe deducted in the first few years than during the remainder of the depreciation period. If we claim the investment credit, our ‘‘tax base’’ in the plant that we can recover through depreciation must be reduced by half of the tax credit; if we claim a production tax credit; there is no reduction in the tax basis for depreciation.

Our subsidiary, Ormat Systems, received from Israel’s Investment Center ‘‘Approved Enterprise’’ status under Israel’s Law for Encouragement of Capital Investments, 1959 (the Investment Law), with respect to two of its investment programs. One such approval was received in 1996 and the other was received in May 2004. In respect of the approval from 1996, Ormat Systems has utilized all the tax benefits it was entitled to. Recently, due to a broad legislative amendment in the Investment Law, Ormat Systems replaced the certificate approval received in May 2004 from Israel’s Investment Center with a ruling from the Israeli Tax Authorities. The ruling was obtained in April 2006. By replacing the approval with a ruling, Ormat Systems maximized the tax benefits it is entitled to under the

Investment Law. As an Approved Enterprise and according to the ruling, Ormat Systems is exempt from Israeli income taxes with respect to income derived from the approved investment for the years 2004 and 2005 and thereafter such income is subject to reduced Israeli income tax rates of 25% for an additional five years. These benefits are subject to certain conditions set forth in the ruling, including among other things, that all transactions between Ormat Systems and our affiliates are at arms length, and that the management and control of Ormat Systems will be from Israel during the whole period of the tax benefits. A change in control should be reported to the Israeli Tax Authorities in order to maintain the tax benefits. In addition, as an industrial company, Ormat Systems is entitled to accelerated depreciation on equipment used for its industrial activities.

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

[1] As the Company's 80% ownership interest in Ormat Leyte Co. Ltd. is accounted for by the equity method, separate financial statements of Ormat Leyte Co. Ltd. have been included pursuant to Rule 3-09 of Regulation S-X.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Ormat Technologies, Inc.'s 2006 and 2005 consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, and an audit of its 2004 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United

States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Ormat Technologies, Inc. and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 12 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation in 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

San Francisco, California
March 9, 2007

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 20,254	$ 26,976
Marketable securities	96,486	43,560
Restricted cash, cash equivalents and marketable securities	56,425	36,732
Receivables:		
Trade	36,463	33,515
Related entities	879	524
Other	5,277	2,629
Due from Parent	1,459	—
Inventories, net	7,403	5,224
Costs and estimated earnings in excess of billings on uncompleted contracts	11,216	8,883
Deferred income taxes	1,819	1,663
Prepaid expenses and other	4,911	3,256
Total current assets	242,592	162,962
Unconsolidated investments	37,207	47,235
Deposits and other	15,081	13,489

Deferred income taxes	6,172	5,376
Property, plant and equipment, net	624,089	491,835
Construction-in-process	169,075	128,256
Deferred financing and lease costs, net	15,800	17,412
Intangible assets, net	50,086	47,915
Total assets	$1,160,102	$914,480
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term bank credit	$ —	$ 3,996
Accounts payable and accrued expenses	70,445	50,048
Billings in excess of costs and estimated earnings on uncompleted contracts	5,803	12,657
Current portion of long-term debt:		
Limited and non-recourse	8,482	2,888
Full recourse	1,000	1,000
Senior secured notes (non-recourse)	40,054	23,754
Due to Parent, including current portion of notes payable to Parent	82,379	32,003
Total current liabilities	208,163	126,346
Long-term debt, net of current portion:		
Limited and non-recourse	22,157	11,252
Full recourse	1,000	2,000
Senior secured notes (non-recourse)	299,316	324,645
Notes payable to Parent, net of current portion	57,841	140,162
Other liabilities	—	1,309
Deferred lease income	78,883	81,569
Deferred income taxes	21,674	22,004
Liabilities for severance pay	13,378	11,409
Asset retirement obligation	16,832	11,461
Total liabilities	719,244	732,157
Minority interest in net assets of a subsidiary	64	64
Commitments and contingencies (Notes 5, 6, 10, 11, 13, 17 and 18)		
Stockholders' equity:		
Common stock, par value $0.001 per share; 200,000,000 shares authorized; 38,101,888 and 31,562,496 shares issued and outstanding, respectively	38	31
Additional paid-in capital	353,399	124,008
Unearned stock-based compensation	—	(153)
Retained earnings	85,053	55,824
Accumulated other comprehensive income	2,304	2,549
Total stockholders' equity	440,794	182,259
Total liabilities and stockholders' equity	$1,160,102	$914,480

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

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

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per share amounts)		
Revenues:			
Electricity:			
Energy and capacity	$106,682	$104,975	$100,281
Lease portion of energy and capacity	86,115	70,963	58,550
Lease income	2,686	1,431	—
Total electricity	195,483	177,369	158,831
Products:			
Related party	3,503	7,959	—
Other	69,951	52,664	60,399
Total products	73,454	60,623	60,399
Total revenues	268,937	237,992	219,230
Cost of revenues:			
Electricity:			
Energy and capacity	77,768	70,328	63,300
Lease portion of energy and capacity	41,345	30,215	26,442
Lease expense	5,243	3,072	—
Total electricity	124,356	103,615	89,742
Products	51,215	45,236	46,336
Total cost of revenues	175,571	148,851	136,078
Gross margin	93,366	89,141	83,152
Operating expenses:			
Research and development expenses	2,983	3,036	2,175
Selling and marketing expenses	10,361	7,876	7,769
General and administrative expenses	18,094	14,320	11,609
Gain on sale of geothermal resource rights	—	—	(845)
Operating income	61,928	63,909	62,444
Other income (expense):			
Interest income	6,560	4,308	1,316
Interest expense:			
Parent	(8,367)	(10,635)	(9,723)
Other	(30,674)	(48,186)	(33,690)
Less — amount capitalized	8,080	3,504	628
Foreign currency translation and transaction losses	(704)	(439)	(146)
Other non-operating income	694	512	112
Income before income taxes, minority interest, and equity in income of investees	37,517	12,973	20,941
Income tax provision	(6,403)	(4,690)	(6,609)
Minority interest in earnings of subsidiaries	(813)	—	(108)
Equity in income of investees	4,146	6,894	3,567
Net income	34,447	15,177	17,791
Other comprehensive income (loss), net of related taxes:			
Gain (loss) in respect of derivative instruments designated for cash flow hedge (net of related tax of $0, $1,518,000 and $(198,000),	—	2,295	(322)

respectively)			
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax of ($224,000), $347,000 and $0, respectively)	(362)	563	—
Change in unrealized gains or losses on marketable available-for-sale securities available-for-sale (net of related tax of $100,000, $8,000 and $0, respectively)	117	13	—
Comprehensive income	$ 34,202	$ 18,048	$ 17,469
Earnings per share:			
Basic	$ 1.00	$ 0.48	$ 0.72
Diluted	$ 0.99	$ 0.48	$ 0.72
Weighted average number of shares used in computation of earnings per share:			
Basic	34,593	31,563	24,806
Diluted	34,707	31,609	24,806

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Divisional Deficit	Unearned Stock-based Compensation	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Total
	(in thousands, except per share data)							
Balance at December 31, 2003	23,214	23	7,002	(11,263)	(86)	41,299	—	36,975
Unearned stock-based compensation	—	—	52	—	(52)	—	—	—
Amortization of unearned stock-based compensation	—	—	—	—	61	—	—	61
Conversion of note payable to Parent to equity	1,161	1	19,999	—	—	—	—	20,000
Reclassification of divisional deficit	—	—	—	10,236	(167)	(10,069)	—	—
Distribution to Parent for purchase of OSL (net of related tax of $3,747,000)	—	—	—	—	—	(1,053)	—	(1,053)
Cash dividend declared, $0.1025 per share	—	—	—	—	—	(2,500)	—	(2,500)
	7,188	7	96,955	—	—	—	—	96,962

Issuance of common stock in initial public offering								
Net income	—	—	—	1,027	—	16,764	—	17,791
Loss in respect of derivative instruments designated for cash flow hedge (net of related tax benefit of $198,000)	—	—	—	—	—	—	(322)	(322)
Balance at December 31, 2004	31,563	31	124,008	—	(244)	44,441	(322)	167,914
Amortization of unearned stock-based compensation	—	—	—	—	91	—	—	91
Cash dividend declared, $0.12 per share	—	—	—	—	—	(3,794)	—	(3,794)
Net income	—	—	—	—	—	15,177	—	15,177
Other comprehensive income, net of related taxes:								
Gain in respect of derivative instruments designated for cash flow hedge (net of related tax of $1,518,000)	—	—	—	—	—	—	2,295	2,295
Amortization of unrealized losses in respect of derivative instruments designated for cash flow hedge (net of related tax benefit of $347,000)							563	563
Change in unrealized gains or losses on marketable securities available-for-sale (net of related tax of $8,000)	—	—	—	—	—	—	13	13
Balance at December 31, 2005	31,563	$31	$124,008	$ —	$(153)	$ 55,824	$2,549	$182,259
Reversal of deferred stock based compensation	—	—	(153)		153	—	—	—
Share based compensation	—	—	1,706		—	—	—	1,706
Cash dividend declared, $0.15 per share	—	—	—		—	(5,218)	—	(5,218)
Issuance of shares of common stock in a follow-on public offering	4,025	4	135,049					135,053
Issuance of shares of common stock in a Block Trade transaction	2,500	3	92,408					92,411
Exercise of options by employees	14	—	215					215
Tax benefit on exercise of options by employees			166					166
Net income	—	—	—		—	34,447	—	34,447
Other comprehensive income, net of related taxes:								
Amortization of unrealized gains in respect of derivative instruments designated for cash flow hedge (net of related tax	—	—	—		—	—	(362)	(362)

benefit of $224,000)								
Change in unrealized gains or losses on marketable securities available-for-sale (net of related tax of $100,000)	—	—	—	—	—	117	117
Balance at December 31, 2006	38,102	$38	$353,399	$ —	$ —	$ 85,053	$2,304	$440,794

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

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ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Cash flows from operating activities:			
Net income	$ 34,447	$ 15,177	$ 17,791
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	43,439	36,006	34,695
Accretion of asset retirement obligation	971	774	588
Share-based compensation	1,706	—	—
Amortization of deferred lease income	(2,686)	(1,431)	—
Extinguishment of deferred financing costs	—	4,180	776
Minority interest in earnings of subsidiaries	813	—	108
Equity in income of investees	(4,146)	(6,894)	(3,567)
Distributions from unconsolidated investments	4,503	5,694	3,996
Realization of loss related to interest rate cap transactions	—	910	1,637
Gain on sale of geothermal resource rights	—	—	(845)
Unrealized loss in respect of derivative instruments, net	559	—	—
Loss (gain) on severace pay fund asset	(1,095)	302	122
Deferred income tax provision (benefit)	(1,528)	(2,182)	3,785
Changes in operating assets and liabilities, net of acquisitions:			
Receivables	(2,502)	(7,415)	3,004
Costs and estimated earnings in excess of billings on uncompleted contracts	(2,333)	(5,719)	(1,242)
Inventories	(2,179)	822	(2,334)
Prepaid expenses and other	(1,573)	(879)	(334)
Deposits and other	(184)	(335)	1,576
Accounts payable and accrued expenses	12,094	7,171	5,099
Due from/to related entities, net	(609)	1,889	(627)

Billings in excess of costs and estimated earnings on uncompleted contracts	(6,854)	6,518	(1,704)
Other liabilities	(20)	(80)	(80)
Proceeds from operating lease transaction	—	83,000	—
Deferred lease transaction costs	—	(3,266)	—
Liabilities for severance pay	1,969	696	1,014
Due from Parent	(1,757)	—	—
Net cash provided by operating activities	73,035	134,938	63,458
Cash flows from investing activities:			
Distributions from unconsolidated investments	2,794	2,844	2,500
Marketable securities, net	(52,654)	45,606	(90,916)
Net change in restricted cash, cash equivalents and marketable securities	(16,285)	(13,696)	(9,039)
Capital expenditures	(159,497)	(116,749)	(38,122)
Decrease of cash resulting from deconsolidation of OLCL	—	—	(1,801)
Proceeds from sale of geothermal resource rights	—	—	2,420
Cash paid for acquisitions, net of cash received	(22,760)	—	(175,950)
Intangible asset acquired	—	(1,800)	—
Increase in severance pay fund asset, net	(872)	(503)	(463)
Repayment from unconsolidated investment	127	890	788
Net cash used in investing activities	(249,147)	(83,408)	(310,583)
Cash flows from financing activities:			
Due to Parent, net	(31,647)	(40,175)	50,836
Proceeds from public offerings, net of issuance costs	227,464	—	96,962
Proceeds from exercise of options by employees	215	—	—
Proceeds from interest rate lock transactions	—	4,334	—
Proceeds from short term bank credit	—	3,996	—
Proceeds from issuance of long-term debt	—	165,000	210,000
Repayments of short-term and long-term debt	(20,736)	(183,975)	(68,194)
Deferred debt issuance costs	(688)	(4,190)	(10,782)
Payment for interest rate caps	—	—	(3,820)
Cash dividends paid	(5,218)	(6,294)	—
Net cash provided by (used in) financing activities	169,390	(61,304)	275,002
Net increase (decrease) in cash and cash equivalents	(6,722)	(9,774)	27,877
Cash and cash equivalents at beginning of period	26,976	36,750	8,873
Cash and cash equivalents at end of period	$ 20,254	$ 26,976	$ 36,750
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest, net of interest capitalized	$ 14,406	$ 24,266	$ 28,531
Income taxes	$ 7,417	$ 2,690	$ 9
Supplemental non-cash investing and financing activities:			
Conversion of note payable to Parent to equity	$ —	$ —	$ 20,000
Increase in accounts payable related to purchases of property, plant and equipment	$ 7,146	$ 7,527	$ 1,306
Accrued liabilities for deferred debt issuance and lease costs	$ —	$ 285	$ —
Increase in asset retirement cost and asset retirement obligation	$ 4,400	$ 22	$ 2,210
Cash dividend declared	$ —	$ —	$ 2,500
Acquisitions — See Notes 2 and 5			

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 — BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Business

Ormat Technologies, Inc. (the ‘‘Company’’), a subsidiary of Ormat Industries Ltd. (the ‘‘Parent’’), is engaged in the geothermal and recovered energy business, including the supply of equipment that is manufactured by the Company and the design and construction of power plants for projects owned by the Company or for third parties. The Company owns and operates geothermal and recovered energy-based power plants in various countries, including the United States of America (‘‘U.S.’’), Kenya, Nicaragua, the Philippines and Guatemala. The Company’s equipment manufacturing operations are located in Israel.

Most of the Company’s domestic power plant facilities are Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (‘‘PURPA’’). The power purchase agreements for certain of such facilities are dependent upon their maintaining Qualifying Facility status. Management believes that all of the facilities were in compliance with Qualifying Facility status as of December 31, 2006.

Recapitalization

On June 29, 2004, the Company amended and restated its certificate of incorporation, pursuant to which the authorized capital stock of the Company was increased from 754 shares of $1.00 par value common stock to 155,892,833 authorized shares, comprised of 150,892,833 shares of $0.001 par value common stock and 5,000,000 shares of $0.001 par value preferred stock, of which 500,000 shares have been designated as Series A Preferred Stock. The Company’s Board of Directors has the authority to issue the undesignated preferred stock in one or more series and to establish the rights, preferences, privileges and restrictions thereof. On October 21, 2004, the Company further amended and restated its certificate of incorporation, pursuant to which the authorized capital stock of the Company was increased from 150,892,833 shares of $0.001 common stock immediately following the split (see below) to 200,000,000 authorized shares of $0.001 par value common stock.

Additionally, on June 29, 2004, the issued and outstanding 151 shares of $1.00 par value common stock were divided and converted (stock split) to 23,214,281 shares of $0.001 par value common stock.

Further, on June 29, 2004, $20.0 million outstanding pursuant to the note payable to the Parent was converted to 1,160,714 shares of $0.001 par value common stock of the Company. Such conversion reduced the amounts payable pursuant to the Parent Loan Agreement and increased the stockholder’s equity by $20.0 million. No gain or loss was recognized as a result of the conversion.

On October 21, 2004, the Board of Directors approved a 1-for-1.325444 reverse stock split of the Company’s common stock. Accordingly, all common share and per common share amounts in these consolidated financial statements have been restated to give retroactive effect to the reverse stock split for all years presented. The par value of the common stock remained at $0.001 per share.

Cash dividend

On October 21, 2004, the Company's Board of Directors declared, approved and authorized the payment of a cash dividend in the aggregate amount of $2.5 million ($0.1025 per share). Such dividend was paid on March 2, 2005 and was presented in the balance sheet as of December 31, 2004, in the ''Due to Parent'' balance.

During the year ended December 31, 2005, the Company's Board of Directors declared, approved and authorized the payment of cash dividends in the aggregate amount of $3.8 million ($0.12 per share). Such dividends were paid during the year ended December 31, 2005.

During the year ended December 31, 2006, the Company's Board of Directors declared, approved and authorized the payment of cash dividends in the aggregate amount of $5.2 million ($0.15 per share). Such dividends were paid during the year ended December 31, 2006.

Initial public offering

In November 2004, the Company completed an initial public offering (''IPO'') of 7,187,500 shares of common stock. Net proceeds to the Company after deducting underwriting fees and offering related expenses, were approximately $97.0 million.

Shelf Registration statement, Follow-On Public Offering and Sale of Shares in a Block Trade

On January 17, 2006, the Company filed a universal shelf registration statement on Form S-3, which was declared effective by the SEC on January 31, 2006. The shelf registration statement provides the Company with the opportunity to issue various types of securities, including debt securities, common stock, warrants and units of the Company, from time to time, in one or more offerings up to a total dollar amount of $1 billion. Pursuant to the shelf registration statement, the Company may periodically offer one or more of the registered securities in amounts, at prices, and on terms to be announced when, and if, the securities are offered. At the time any offering is made under the shelf registration statement, the offering specifics will be set out in a prospectus supplement.

On April 10, 2006, the Company completed a follow-on public offering of 3,500,000 shares of common stock at a price of $35.50 per share, under the shelf registration statement mentioned above. In addition, on April 17, 2006, 525,000 additional shares of common stock were sold at the abovementioned price pursuant to the exercise of the underwriters' over-allotment option. Net proceeds to the Company after deducting underwriting fees and commissions and estimated offering expenses associated with the offering were approximately $135.1 million.

On December 19, 2006, the Company completed a sale of 2,500,000 shares of common stock to Lehman Brothers in a block trade at a price of $37.50 per share, under the shelf registration statement mentioned above. Net proceeds to the Company after deducting underwriting fees and commissions and estimated offering expenses associated with the offering were approximately $92.4 million.

Rounding

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

Reclassification

Certain comparative figures have been reclassified to conform to the current year presentation.

Basis of presentation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The Company has an 85% interest in OrYunnan Geothermal Co. Ltd. (‘‘OrYunnan’’) that is accounted for under the consolidation method of accounting and an 80% interest in Ormat Leyte Co. Ltd. (‘‘OLCL’’) that was accounted for under the consolidation method of accounting until March 31, 2004 and under the equity method of accounting thereafter. The Company’s investment in Orzunil I de Electricidad, Limitada (‘‘Orzunil’’) was consolidated beginning March 13, 2006 when the Company increased its ownership interest to 71.8%. On August 16, 2006, the Company increased its ownership interest to 100% (see Note 5). Prior to March 13, 2006, this investment was accounted for using the equity method of accounting. Intercompany accounts and transactions have been eliminated in the consolidation.

In November 1999, the Company, through a wholly owned subsidiary, entered into an agreement with Yunnan Province Geothermal Development Co. (‘‘YPGD’’) to form OrYunnan, a limited liability joint venture, whereby the Company is to contribute, for an 85% ownership interest, $2,550,000 and YPGD is to contribute, for the remaining 15% ownership interest, $450,000. Pursuant to such agreement, 15% of the capital contribution was made in April 2000, and the remaining portion is to be paid within 60 days after the date on which a power purchase agreement is executed. OrYunnan is currently in the process of negotiating a power purchase agreement. OrYunnan was formed for the purpose of utilizing, for electric power generation, all of the geothermal resources of Teng Chong County of the Yunnan Province in the People’s Republic of China.

OLCL is a limited partnership established for the purpose of developing, financing, constructing, owning, operating, and maintaining geothermal power plants in Leyte Province, the Philippines.

The Company accounts for its interests in partnerships and companies in which it has equal to or less than a 50% ownership interest under the equity method. 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 in investments accounted for under the equity method have been reflected as ‘‘Equity in income of investees’’ on the Company’s consolidated statements of operations and comprehensive income.

Adoption of FIN No. 46R

In January 2003, the Financial Accounting Standards Board (‘‘FASB’’) issued Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB 51 (‘‘FIN No. 46’’), and amended it by issuing FIN No. 46R in December 2003. Among other things, FIN No. 46R generally deferred the effective date of FIN No. 46 to the quarter ended March 31, 2004. The objectives of FIN No. 46R are to provide guidance on the identification of Variable Interest Entities (‘‘VIEs’’) for which control is achieved through means other than ownership of a majority of the voting interest of the entity, and how to determine which company (if any), as the primary beneficiary, should consolidate the VIE. A variable interest in a VIE, by definition, is an asset, liability, equity, contractual arrangement or other economic interest that absorbs the entity’s economic variability.

Effective as of March 31, 2004, the Company adopted FIN No. 46R. In connection with the adoption of FIN No. 46R, the Company concluded that OLCL, in which the Company has an 80% ownership interest, should be deconsolidated. OLCL’s operating results continued to be accounted for using the consolidation method of accounting for the three month period ended March 31, 2004. Effective April 1, 2004, the Company’s ownership interest in OLCL is accounted for using the equity method of accounting. The Company’s maximum exposure to loss as a result of its involvement with OLCL is estimated to be $5.3 million, which is the Company’s net investment at December 31, 2006.

The Company also has variable interests in certain other consolidated wholly owned VIEs that will continue to be consolidated because the Company is the primary beneficiary. Further, the Company has concluded that the Company’s remaining significant equity investments do not require consolidation as they are not VIEs.

Purchase of the power generation business from the Parent

As of July 1, 2004, a wholly owned subsidiary of the Company, Ormat Systems Ltd. (‘‘OSL’’), an Israeli company, acquired from the Parent for $11.0 million the power generation business which includes the manufacturing and sale of energy-related products pertaining mainly to the geothermal and recovered energy industry.

The Company considers this business to be synergistic with its ownership and operation of geothermal power plants as well as to the construction of the projects (on a turnkey basis). In addition

to acquiring the tangible net assets of the power generation business, OSL assumed the title and interest to: (i) certain related contracts; and (ii) liabilities and rights under agreements with employees and consultants, and obtained a perpetual license of all intellectual property pertaining to the power generation business from the Parent.

In connection with the acquisition, OSL and the Parent have entered into an agreement whereby OSL will provide to the Parent, for a monthly fee of $10,000 (adjusted annually partially for changes in the Israeli Consumer Price Index), certain corporate administrative services, including the services of executive officers. In addition, OSL has agreed to provide the Parent with services of certain skilled engineers at OSL’s cost plus 10%. Such agreements may be terminated by either party after the initial term which ends in 2009.

Also in connection with the acquisition, OSL entered into a rental agreement with the Parent for the use of office and manufacturing facilities in Yavne, Israel, for a monthly rent of $52,000, adjusted annually for changes in the Israeli Consumer Price Index, plus tax and other costs to maintain the properties. The term of the rental agreement is 59 months and it expires in June 2009, which term has been extended by a consent of the Israeli Land Administration for a period the shorter of: (i) 25 years (including the initial term) or (ii) the remaining period of the underlying lease agreement with the Israel Land Administration (which terminates between 2018 and 2047).

The Company has recorded the purchase of the power generation business at historical net book value, and has accounted for the purchase as a transfer of assets between entities under common control in a manner similar to the pooling of interests; accordingly, all prior period consolidated financial statements of the Company have been restated to include the results of operations, financial position, and cash flows of the power generation business.

The financial statements for all years presented include the historical financial information of the Company prior to the acquisition of the power generation business, combined with the historical financial information of the acquired power generation business which was carved out of the Parent for all years presented. The difference between the assets and liabilities of the power generation business consists of accumulated retained earnings (deficit) as well as amounts due to/from Parent resulting from cash transfers. Such amounts have been aggregated and presented in the statements of stockholders' equity as ''divisional deficit'' because it is not possible to distinguish the beginning balance as the records were not available to accurately break out the two components. On July 1, 2004, the effective date of the transaction, the divisional deficit was reclassified to retained earnings and unearned stock-based compensation. Retained earnings in the statements of stockholders' equity for all years prior to the year ended December 31, 2004 represent the retained earnings of the Company prior to the acquisition of the power generation business.

The preparation of these financial statements included the use of ''carve out'' accounting procedures wherein certain assets, liabilities, revenues and expenses historically recorded or incurred at the Parent level, which were related to OSL, have been identified and allocated as appropriate to present the financial position, operating results, and cash flows of OSL for the years presented.

The statements of operations for OSL for the period from January 1, 2004 to June 30, 2004 were carved out using specific identification for revenues and cost of revenues, research and development expense, selling and marketing expenses, general and administrative expenses and interest income and expense. The income tax provision was recalculated based on the separate return method pursuant to Statement of Financial Accounting Standards (''SFAS'') No. 109, Accounting for Income Taxes.

Of the $11.0 million purchase price, the Company paid $4.8 million in cash and assumed $6.2 million in debt and other liabilities. The excess of the consideration paid over the historical net book value of the purchased business has been recorded as a distribution to the Parent, which reduced stockholders' equity by approximately $4.8 million at July 1, 2004. Because the deferred income taxes

at June 30, 2004 had a full valuation allowance, there was no tax effect for the difference between the book and tax basis of the purchased assets and liabilities.

Cash and cash equivalents

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

Marketable securities

Marketable securities consist of debt securities (mainly auction rate securities and commercial papers). The Company accounts for such securities in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. The Company determines the appropriate classification of all marketable securities as held-to-maturity, available-for-sale or trading at the time of the purchase and re-evaluates such classification at each balance sheet date. At December 31, 2006 and 2005 all of the Company's investments in marketable securities were classified as available-for-sale securities and as a result, were reported at their fair value based upon the quoted market prices of such securities at year end. Net unrealized gains or losses are reported as a component of accumulated other comprehensive income (loss) in stockholders' equity. Net realized gains or losses are reported in interest income.

The marketable securities are included in the balance sheets at December 31, 2006 and 2005, as follows:

	December 31,	
	2006	2005
	(dollars in thousands)	
Marketable securities	$ 96,486	$ 43,560
Amount presented among short-term restricted cash, cash equivalents and marketable securities	16,921	14,645
Total	$ 113,407	$ 58,205

The cost of the marketable securities at December 31, 2006 and 2005 was $113,232,000 and $58,224,000, respectively.

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 reserve, cash collateral and operating fund accounts that have been classified as restricted cash, cash equivalents and marketable securities. Funds that will be used to satisfy obligations due during the next twelve months are classified as current restricted cash, cash equivalents and marketable securities, with the remainder classified as non-current restricted cash, cash equivalents and marketable securities. Such amounts are invested primarily in money market accounts, auction rate securities and commercial papers with a minimum investment grade of ''AA''. Auction rate securities are classified as available-for-sale.

Certain of the restricted cash accounts can be replaced by a letter of credit, and as further described in Note 18, as of December 31, 2006, three letters of credit aggregating $21.9 million were issued by the Company to release restriction on funds that were used as collateral for OFC's 8¼% Senior Secured Notes (''OFC Senior Secured Notes'') and OrCal's 6.21% Senior Secured Notes (''OrCal Senior Secured Notes'').

Concentration of credit risk

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

The Company places its temporary cash investments and marketable securities with high credit quality financial institutions located in the U.S. and in foreign countries. At December 31, 2006 and 2005, the Company had deposits totaling $13,068,000 and $9,889,000, respectively, in six and four, respectively, U.S. financial institutions that were federally insured up to $100,000 per account. At December 31, 2006 and 2005, the Company's deposits in foreign countries of approximately $15,321,000 and $11,935,000, respectively, were not insured.

At December 31, 2006 and 2005, accounts receivable related to operations in foreign countries amounted to approximately $16,957,000 and $11,017,000, respectively. At December 31, 2006 and 2005, accounts receivable from the Company's major customers that have generated 10% or more of its revenues (see Note 15) amounted to approximately 49% and 59%, respectively, of the Company's accounts receivable.

Southern California Edison Company (''SCE'') accounted for 30.0%, 36.1% and 41.4% of the Company's total revenues for the years ended December 31, 2006, 2005 and 2004, respectively. SCE is also the power purchaser and revenue source for the Mammoth project, which is accounted for separately under the equity method.

Sierra Pacific Power Company accounted for 12.8%, 14.1% and 12.9% of the Company's total revenues for the years ended December 31, 2006, 2005 and 2004, respectively.

Hawaii Electric Light Company accounted for 15.1%, 15.2% and 7.1% of the Company's total revenues for the years ended December 31, 2006, 2005 and 2004, respectively.

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

Inventories

Inventories consist primarily of raw material parts and sub assemblies for power units, and are stated at the lower of cost or market value, using the moving-average cost method and are stated net of provision for slow-moving and obsolescence, which was not significant at December 31, 2006 and 2005.

Deposits and other

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

Property, plant and equipment

Property, plant and equipment are stated at cost. All costs associated with the acquisition, development and construction incurred as part of the 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 are depreciated using the straight-line method over the term of the relevant power purchase agreement, which range from 12 to 25 years (see Note 13). The geothermal power plant in Nicaragua is to be fully depreciated over the period that the plants are owned by the Company. The other assets are depreciated using the straight-line method over the following estimated useful lives of the assets:

Leasehold improvements	15-20 years
Machinery and equipment — manufacturing	10 years
Machinery and equipment — computers	3-5 years
Office equipment — furniture and fixtures	5-15 years
Office equipment — other	5-10 years
Automobiles	5-7 years

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

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 $8,080,000, $3,504,000 and $628,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

Asset retirement obligation

As required by SFAS No. 143, Accounting for Obligations Associated with the Retirement of Long-Lived Assets, which was amended by FASB Interpretation (''FIN'') No. 47, Accounting for Conditional Retirement Obligations, an Interpretation of FASB Statement No. 143, 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 geothermal 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. 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 statement of operations. Accumulated

amortization related to deferred financing costs amounted to $4,342,000 and $2,422,000 at December 31, 2006 and 2005, respectively. Amortization expense for the years ended December 31, 2006, 2005 and 2004 amounted to $1,920,000, $6,087,000 and $2,705,000, respectively. Amortization expense for the year ended December 31, 2005 includes $4,180,000 relating to the write-off of the remaining deferred financing costs when the Beal Bank loan was repaid (see Note 9).

Deferred transaction costs relating to the Puna operating leases (see Note 10) in the amount of $4,333,000 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 statement of operations. Accumulated amortization related to deferred lease costs amounted to $301,000 and $117,000 at December 31, 2006 and 2005, respectively. Amortization expense for the years ended December 31, 2006 and 2005 amounted to $184,000 and $117,000, respectively.

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Intangible assets

Intangible assets consist of allocated acquisition costs of power purchase agreements, which are amortized over the 13 to 25-year terms of the agreements using the straight-line method.

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

Long-lived assets which consist of property, plant and equipment, power purchase agreements andunconsolidated investments are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net undiscounted cash flows expected to be generated by the asset. If such 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 the fair value of the assets. 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, future estimates as to the recoverability of such assets may change based on revised circumstances.

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 currently 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 incorporates the use of interest rate swaps and interest rate caps to minimize significant fluctuation in cash flows and/or earnings that are caused by 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 are subsequently reclassified into earnings when interest on the

related debt is paid. Gains or losses on contracts that are not designated to qualify as a cash flow hedge are included as a component of interest expense.

Foreign currency translation

The functional currency of all foreign entities is the reporting currency (U.S. dollar). For these entities, monetary assets and liabilities are translated at the current exchange rate, while non-monetary items are translated at historical rates. Income and expense items are translated at the average exchange rate for the year, except for depreciation, which is translated at historical rates. Translation adjustments and transaction gains or losses are included in results of operations.

Comprehensive income reporting

Comprehensive income includes net income plus other comprehensive income, which for the Company consists of unrealized gain or loss on marketable securities available-for-sale and the mark-to-market gains or losses on derivative instruments designated as a cash flow hedge.

Revenues and cost of revenues

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

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

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Revenues related to the sale of electricity from geothermal and recovered energy power plants and capacity payments are recorded based upon output delivered and capacity provided at rates specified under relevant contract terms. For power purchase agreements (‘‘PPAs’’) agreed to, modified or acquired in business combinations on or after July 1, 2003 (effective date of Emerging Issues Task Force Issue (‘‘EITF’’) No. 01-08, Determining whether an Arrangement Contains a Lease), revenues related to the lease element of the PPAs are included as ‘‘lease portion of energy and capacity’’ revenues, with the remaining revenues related to the production and delivery of energy presented as ‘‘energy and capacity’’. Lease income and expense are recognized ratably over the lease periods.

Revenues from engineering, operating services, and parts and product sales are recorded upon providing the service or delivery of the products and parts. Revenues from the supply and/or construction of geothermal and recovered energy power plant equipment and other equipment on behalf of others are recognized on the percentage completion method. Revenue is 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.

Warranty on products sold

The Company generally provides a one-year warranty against defects in workmanship and materials related to the sale of products for electricity generation. 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, 2006, 2005 and 2004.

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 U.S. Department of Energy are offset against the related research and development expenses. Such grants amounted to $252,000, $1,275,000 and $86,000 during the years ended December 31, 2006, 2005, and 2004, respectively.

Advertising expense

Advertising costs are expensed as incurred and totaled $96,000, $180,000 and $74,000 for the years ended December 31, 2006, 2005, and 2004, respectively.

Patent expense

Patents are internally developed, and therefore costs are expensed as incurred and totaled $122,000, $252,000 and $290,000 for the years ended December 31, 2006, 2005, and 2004, respectively.

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. The effects of future changes in tax laws or rates are not

anticipated. 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.

Earnings per share

Basic earnings per share is computed by dividing net income available to common stockholders by the weighted average number of shares of common stock outstanding for the year. The Company does not have any equity

instruments that are dilutive, except for employee stock options which were granted in the years ended December 31, 2006, 2005 and 2004 and whose dilutive effect on the earnings per share for the years ended December 31, 2005 and 2004 is immaterial. The stock options granted to employees of the Company in the Parent's stock are not dilutive to the Company's earnings per share.

Fair value of financial instruments

The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of those instruments. Marketable securities are presented at fair value. The fair value of long-term debt is estimated based on the current borrowing rates for similar issues, which approximates carrying amount for long-term debt, except for the following debt:

	Fair Value December 31,		Carrying Amount December 31,	
	2006	2005	2006	2005
	(dollars in millions)		(dollars in millions)	
Senior loans:				
International Finance Corporation Loan A	$ 7.5	$ —	$ 7.0	$ —
International Finance Corporation Loan B	4.0	—	3.9	—
Commonwealth Development Corporation Loan	8.7	—	8.5	—
Senior Secured Notes:				
Ormat Funding Corp. (''OFC'')	182.3	185.2	178.7	183.4
OrCal Geothermal Inc. (''OrCal'')	151.5	165.0	160.7	165.0
Parent's Loan	90.8	125.2	89.5	121.1
Parent's Note	47.8	45.3	50.7	50.7

Accounting estimates

The preparation of financial statements in conformity with generally accepted accounting principles 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.

New accounting pronouncements

New accounting pronouncements effective in the year ended December 31, 2006

SFAS No. 123R — Share-Based Payments

Effective January 1, 2006, the Company adopted SFAS No. 123(R), Share-Based Payments, (''SFAS No. 123R''), which establishes the accounting for employee stock-based awards. Prior to

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January 1, 2006, the Company accounted for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion No. 25 (‘‘APB No. 25’’), Accounting for Stock Issued to Employees, and related interpretations. Under APB No. 25, compensation cost was recognized based on the difference, if any, on the date of grant between the fair value of the Company’s stock and the amount an employee must pay to acquire the stock (see Note 12).

SFAS No. 151 — Inventory Costs

In November 2004, the FASB issued SFAS No. 151, Inventory Costs — An Amendment of ARB 43, Chapter 4. SFAS No. 151 amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing, to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs, and wasted material. SFAS No. 151 requires that those items be recognized as current period charges. In addition, SFAS No. 151 requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. The provisions of SFAS No. 151 are applied prospectively to inventory costs incurred beginning January 1, 2006. The adoption by the Company of SFAS No. 151, effective January 1, 2006, did not have any impact on its results of operations or financial position.

SFAS No. 154 — Accounting Changes and Error Corrections

In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections. SFAS No. 154 replaces APB Opinion No. 20, Accounting Changes and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements. SFAS No. 154 requires that a voluntary change in accounting principle be applied retrospectively with all prior period financial statements presented based on the new accounting principle. SFAS No. 154 also requires that a change in method of depreciating or amortizing a long-lived non-financial asset be accounted for prospectively as a change in estimate, and correction of errors in previously issued financial statements should be termed a restatement. SFAS No. 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005 (January 1, 2006 for the Company). The adoption by the Company of SFAS No. 154, effective January 1, 2006, did not have any impact on its results of operations or financial position.

EITF Issue No. 04-5 — Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights

In June 2005, the FASB issued EITF Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights. EITF Issue No. 04-5 provides guidance in determining whether a general partner controls a limited partnership and therefore should consolidate the limited partnership. EITF Issue No. 04-5 states that the general partner in a limited partnership is presumed to control that limited partnership and that the presumption may be overcome if the limited partners have either: (i) the substantive ability to dissolve or liquidate the limited partnership or otherwise remove the general partner without cause, or (ii) substantive participating rights. The effective date for applying the guidance in EITF No. 04-5 was: (i) June 29, 2005 for all new limited partnerships and existing limited partnerships for which the partnership agreement was modified after that date, and (ii) no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005 (January 1, 2006 for the Company), for all other limited partnerships. The adoption by the Company of EITF Issue No. 04-5, effective January 1, 2006, did not have any impact on the Company’s consolidated financial statements.

SAB No. 108 — Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements (‘‘SAB

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

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No. 108’’). SAB No. 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year’s misstatement. The SEC staff believes that registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material and therefore must be quantified. SAB No. 108 is effective for fiscal years ending on or after November 15, 2006 (December 31, 2006 for the Company). The adoption by the Company of SAB No. 108, effective December 31, 2006, did not have any impact on its results of operations and financial position.

New accounting pronouncements effective in future years

SFAS No. 155 — Accounting for Certain Hybrid Financial Instruments

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments. SFAS No. 155 replaces certain provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities. SFAS No. 155 permits fair value measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. It clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133. SFAS No. 155 also establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation. It also clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives and amends SFAS No. 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS No. 155 is effective for all financial instruments acquired or issued after January 1, 2007. The Company does not expect that the adoption of SFAS No. 155 will have a material impact on its results of operations or financial position in future periods.

FIN No. 48 — Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109

In June 2006, the FASB issued FIN No. 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN No. 48 is effective January 1, 2007. The Company is currently assessing the impact of FIN No. 48 and has not yet determined the impact that its adoption will have on its results of operations and financial position.

EITF Issue No. 06-3 — How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)

In June 2006, the FASB issued EITF Issue No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation). The requirements of EITF Issue No. 06-3 apply to any tax assessed by a governmental authority that is imposed concurrently on a specific revenue-producing transaction between a seller and a customer. Examples of taxes subject to Issue No. 06-3 include sales, use, value added, and some excise taxes. EITF Issue No. 06-3 excludes taxes that are assessed on gross receipts or that are imposed during the process of obtaining inventory. Companies will be required to disclose

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their accounting policy regarding the presentation of taxes subject to EITF Issue No. 06-3, and the amounts of such taxes that are included in income on a gross basis, if those amounts are significant. EITF Issue No. 06-3 is effective January 1, 2007. The Company does not expect EITF Issue No. 06-3 to have an impact on its financial statements in future periods.

SFAS No. 157 — Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 clarifies the principle that fair value should be based on the assumptions market participants would use when pricing an asset or liability and establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for the Company) and interim periods within those fiscal years, with early adoption permitted. The Company is currently assessing the impact of SFAS No. 157, and has not yet determined the impact that its adoption will have on its results of operations or financial position.

NOTE 2 — BUSINESS ACQUISITIONS

The Steamboat 2/3 Project and Meyberg Property

On February 11, 2004, the Company acquired 100% of the outstanding shares of capital stock of Steamboat Development Corp. (‘‘SDC’’) and certain real property (‘‘Meyberg Property’’) from an unrelated party. SDC owned certain leasehold interests as a lessee in the two Steamboat 2/3 geothermal power plants and certain related geothermal leases. On February 13, 2004, the Company acquired all of the beneficial rights, title, and interest in the Steamboat 2/3 geothermal power plants from the lessor. The Company acquired SDC and the Meyberg Property to increase its geothermal power plant operations in the U.S. The Company acquired the lessee and lessor positions of the Steamboat 2/3 geothermal power plants for a combined purchase price of approximately $82.0 million, plus transaction cost of approximately $0.8 million. The results of SDC’s operations have been included in the consolidated financial statements since February 11, 2004.

The Steamboat Hills Project

On May 20, 2004, the Company completed the acquisition of 100% of the equity interests of Yankee Caithness Joint Venture, L.P. (‘‘Yankee’’), which was subsequently renamed as Steamboat Hills, from unrelated parties for a purchase price of approximately $20.3 million, including acquisition costs of approximately $0.1 million. Yankee owns and operates a geothermal electric generation plant, located in Steamboat Springs, Nevada. The Company purchased Yankee in order to increase its geothermal power plant operations. The results of Steamboat Hills’ operations have been included in the consolidated financial statements since May 20, 2004.

The Puna Project

On June 3, 2004, the Company completed the acquisition of 100% of the equity interests of Puna Geothermal Venture (‘‘PGV’’) from an unrelated party for a purchase price of $72.9 million, including acquisition costs of approximately $0.2 million. PGV operates a geothermal power plant (‘‘Puna Project’’) located on the Big Island of Hawaii. The Company purchased PGV in order to increase its geothermal power plant operations in the U.S. The results of PGV’s operations have been included in the consolidated financial statements since June 3, 2004.

The Steamboat 2/3 Project, the Meyberg Property, the Steamboat Hills Project and the Puna Project acquisitions have been accounted for under the purchase method of accounting and the

acquired depreciable assets and intangibles are being depreciated over their estimated useful lives of 14 to 23 years. The purchase price (including of the lessee and lessor position in the Steamboat 2/3 Project) has been allocated to the fair value of assets and liabilities based on independent valuations and management’s estimates as follows:

	Steamboat 2/3 Project and Meyberg Property	Steamboat Hills Project	Puna Project	Total
		(dollars in thousands)		
Accounts receivable assumed	$ 1,944	$ —	$ 1,870	$ 3,814
Property, plant and equipment	78,719	20,809	56,881	156,409
Intangibles (power purchase agreement)	4,499	—	14,992	19,491
Accounts payable and other liabilities assumed	(1,455)	—	(179)	(1,634)
Asset retirement obligation	(941)	(548)	(641)	(2,130)
Total cash paid	$ 82,766	$ 20,261	$ 72,923	$ 175,950

The following unaudited pro forma financial information for the year ended December 31, 2004 assumes the Steamboat 2/3 Project and Meyberg Property, the Steamboat Hills Project and the Puna Project acquisitions occurred as of the beginning of the year, after giving effect to certain adjustments, including the amortization of intangible assets, interest expense on acquisition debt, depreciation based on the adjustments to the fair market value of the property, plant and equipment acquired, and related income tax effects. The pro forma results have been prepared for comparative purposes only and are not necessarily indicative of the results of operations that may occur in the future or that would have occurred had the acquisition of the Steamboat 2/3 Project and Meyberg Property, the Steamboat Hills Project and the Puna Project been affected on the date indicated.

	Year Ended December 31, 2004 (dollars in thousands, except per share amounts)
Revenues	$ 231,788
Net income	17,789
Basic and diluted earnings per share	$ 0.72

The Zunil Project

On March 13, 2006 and on August 16, 2006, the Company acquired an additional 50.8% and 28.2%, respectively, ownership interest in Orzunil I de Electricidad, Limitada (‘‘Orzunil’’), thereby increasing the Company’s ownership interest to 100% (see Note 5).

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NOTE 3 — INVENTORIES

Inventories consist of the following:

	December 31,	
	2006	2005
	(dollars in thousands)	
Raw materials and purchased parts for assembly	$ 3,397	$ 1,521
Self-manufactured assembly parts and finished products	4,006	3,703

Total	$ 7,403	$ 5,224

NOTE 4 — COST AND ESTIMATED EARNINGS ON UNCOMPLETED CONTRACTS

	December 31,	
	2006	2005
	(dollars in thousands)	
Costs and estimated earnings incurred on uncompleted contracts	$ 18,967	$ 39,142
Less billings to date	13,554	42,916
Total	$ 5,413	$ (3,774)

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

	December 31,	
	2006	2005
	(dollars in thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 11,216	$ 8,883
Billings in excess of costs and estimated earnings on uncompleted contracts	(5,803)	(12,657)
Total	$ 5,413	$ (3,774)

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

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NOTE 5 — UNCONSOLIDATED INVESTMENTS

Unconsolidated investments in power plant projects consist of the following:

	December 31,	
	2006	2005
	(dollars in thousands)	
Orzunil:		

Investment	$ —	$ 3,807
Advances	—	3,712
	—	7,519
Mammoth	31,913	34,240
OLCL	5,294	5,476
Total	$ 37,207	$ 47,235

From time to time, the unconsolidated power plants make distributions to their owners. Such distributions are deducted from the investments in such power plants.

The Zunil Project

Prior to March 13, 2006, the Company had a 21.0% ownership interest in Orzunil I de Electricidad, Limitada (‘‘Orzunil’’), a limited responsibility company incorporated in Guatemala and established for the purpose of generating power by means of a geothermal power plant in the Province of Quetzaltenango in Guatemala. The Company operates and maintains the geothermal power plant and the power purchaser supplies geothermal fluid to the power plant.

On March 13, 2006, the Company acquired a 50.8% ownership interest in Orzunil and increased its then existing 21.0% ownership interest to 71.8%. The purchase price of this acquisition was $15.4 million, including acquisition costs of approximately $0.6 million.

The Company’s 21.0% ownership interest in Orzunil prior to the abovementioned acquisition was accounted for under the equity method of accounting as the Company had the ability to exercise significant influence, but not control, over Orzunil. As a result of the acquisition of the additional 50.8% interest in Orzunil, the financial statements of Orzunil were consolidated with the Company’s financial statements effective March 13, 2006.

On August 16, 2006, the Company completed the acquisition from each of CDC Group plc (‘‘CDC’’) and International Finance Corporation (‘‘IFC’’), both of which are the Zunil Project’s senior lenders, a 14.1% ownership interest in Orzunil (for a total of 28.2%), thereby increasing the Company’s then existing 71.8% ownership interest to 100%. The total purchase price of both acquisitions was $7.4 million, including acquisition costs of approximately $0.9 million.

The abovementioned acquisitions have been accounted for under the purchase method of accounting and the acquired assets are being depreciated over their estimated useful lives of 13.5 years. The purchase prices of all the abovementioned acquisitions ($22.8 million) have been allocated to the fair value of assets and liabilities based on an independent valuation and management’s estimates as follows:

(dollars in thousands)

Cash and cash equivalents	$ 8
Restricted cash	3,408
Accounts receivable assumed	3,176
Property, plant and equipment	42,621
Intangibles (power purchase agreement)	5,250
Accounts payable and other liabilities assumed	(1,241)
Long-term loans assumed (including current portion)	(23,210)
	30,012
Less: the Company's investment prior to acquisition	(7,244)
Total purchase price allocation	$ 22,768

The revenues of Orzunil and the Company's share in the net income of Orzunil were $10,343,000 and $3,018,000, respectively, for the period from March 13, 2006 to December 31, 2006.

The Company's equity in income of Orzunil was not significant for each of the years presented in these financial statements.

The Mammoth Project

On December 18, 2003, the Company acquired a 50% interest in the Mammoth Project, which is comprised of three geothermal power plants located near the city of Mammoth, California. The purchase price was less than the underlying net equity of Mammoth by approximately $9.3 million. As such, the basis difference will be amortized over the remaining useful life of the property, plant and equipment and the power purchase agreements, which range from 12 to 17 years. Effective December 18, 2003, the Company operates and maintains the geothermal power plants under an operating and maintenance (''O&M'') agreement. The Company's 50% ownership interest in Mammoth is accounted for under the equity method of accounting as the Company has the ability to exercise significant influence, but not control, over Mammoth.

The condensed financial position and results of operations of Mammoth are summarized below:

	December 31,	
	2006	2005
	(dollars in thousands)	
Condensed balance sheets:		
Current assets	$ 3,425	$ 7,430
Non-current assets	79,942	82,550
Current liabilities	667	1,114
Non-current liabilities	3,130	3,708
Partners' Capital	79,570	85,158

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Condensed statements of operations:			
Revenues	$ 15,339	$ 15,782	$ 15,815
Gross margin	1,657	4,021	3,830
Net income	1,412	3,824	3,251
Company's equity in income of Mammoth:			
50% of Mammoth net income	$ 706	$ 1,912	$ 1,761
Plus amortization of basis difference	593	593	593
	1,299	2,505	2,354
Less income taxes	(493)	(952)	(894)
Total	$ 806	$ 1,553	$ 1,460

The Mammoth project sells its electrical output to Southern California Edison Company (''SCE'') under three separate power purchase agreements. Under the G-1 power purchase agreement, in certain circumstances, SCE or its affiliates has a right of first refusal to acquire the plant.

The Leyte Project (''OLCL'')

The Company holds an 80% interest in OLCL (which owns the Leyte Project); however, as further discussed in Note 1, upon the adoption of FIN No. 46R, the balance sheet of OLCL was deconsolidated as of March 31, 2004, and the income and cash flow statements have been deconsolidated effective April 1, 2004.

The condensed financial position and results of operations of OLCL are summarized below:

	December 31,	
	2006	2005
	(dollars in thousands)	
Condensed balance sheets:		
Current assets	$ 7,548	$ 7,972
Non-current assets	4,632	11,267
Current liabilities	4,782	6,083
Non-current liabilities	—	3,810
Stockholders' equity	7,398	9,346

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Year Ended December 31,		Period from April 1, 2004 to December 31,
	2006	2005	2004
	(dollars in thousands)		
Condensed statements of operations:			
Revenues	$ 13,715	$ 13,134	$ 8,217
Gross margin	6,417	6,246	2,592
Net income	2,787	5,271	838
Company's equity in income of OLCL:			
80% of OLCL net income	$ 2,230	$ 4,217	$ 670
Plus amortization of deferred revenue on intercompany profit ($0.8 million unamortized balance at December 31, 2006)	1,384	708	789
Total	$ 3,614	$ 4,925	$ 1,459

OLCL's operating results for all periods prior to March 31, 2004 have been accounted for on the consolidated method of accounting, and effective April 1, 2004, the Company's ownership interest in OLCL is accounted for using the equity method of accounting.

In 1996, OLCL entered into a Build, Operate, and Transfer (''BOT'') agreement with PNOC-Energy Development Corporation (''PNOC'') in connection with the four geothermal power generation plants, with a total capacity of 49MW, located in Leyte, Philippines. The BOT agreement calls for OLCL to design, construct, own, and operate geothermal electricity generating plants, utilizing the geothermal resources of the Leyte Geothermal Power Optimization Project Area. During 1997, the power plants started commercial operations and began selling power to PNOC under a ten year power purchase agreement (tolling arrangement). OLCL receives capacity and energy fees from PNOC established by the BOT agreement. Fees are paid each month through the term of the BOT agreement and vary based on plant performance. OLCL owns the plants for a ten-year period ending September 2007, at which time they will be transferred to PNOC for no further consideration. The Company does not anticipate any material financial loss as a result of such transfer, although going forward this will reduce the Company's foreign generation capacity by 49 MW.

In connection with the construction of the four geothermal power generation plants, OLCL obtained a term loan (''Term Loan'') amounting to approximately $44.5 million from the Export-Import Bank of the government of the United States (''Eximbank''). Principal is payable in equal quarterly installments through July 2007. Interest on the Term Loan is at a fixed rate of 6.54% and is payable quarterly. The balance of the Term Loan as of December 31, 2006 and 2005 is $3,810,000 and $8,890,000, respectively. The Term Loan is collateralized by a mortgage on all real property, an assignment of revenues, and the pledge of partnership interests in OLCL. There are various covenants under the Term Loan, which include maintaining minimum levels of equity ratio, as defined, and limitations on additional indebtedness and payment of dividends. As of December 31, 2006, Management believes that OLCL was in compliance with the covenants under the Term Loan.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 6 — PROPERTY, PLANT AND EQUIPMENT

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

	December 31,	
	2006	2005
	(dollars in thousands)	
Land	$ 11,503	$ 11,521
Leashold improvements	1,114	966
Machinery and equipment	15,401	13,558
Office equipment	3,058	2,840
Automobiles	1,720	1,278
Gethermal and recovered energy generation power plants, including geothermal wells:		
United States of America	582,567	471,886
Foreign countries	120,852	68,547
Asset retirement cost	14,078	9,678
	750,293	580,274
Less accumulated depreciation	(126,204)	(88,439)
Property, plant and equipment, net	$ 624,089	$ 491,835

Depreciation expense for the years ended December 31, 2006, 2005 and 2004 amount to $38,659,000, $31,210,000 and $31,729,000, respectively.

U.S. operations:

The net book value of the property, plant and equipment, including construction in process, located in the United States is approximately $636,332,000 and $514,176,000 as of December 31, 2006 and 2005, respectively.

Foreign operations:

During 1998, the Company entered into a power purchase agreement with Kenya Power and Lighting Co. Ltd. (‘‘KPLC’’) , the Kenyan parastatal electricity transmission and distribution company. Under the agreement, the Company agreed to design, construct and operate geothermal power plants in Kenya in several phases. Upon the completion of construction of each phase, KPLC is committed to purchase the electricity generated by the power plants for a minimum of 20 years under the terms of the power purchase agreement. Phase I of the Olkaria III project, which generates 13 MW, has been completed and the net book value of the assets related to the generation power plant and the related wells amounted to approximately $28,813,000 and $30,591,000 at December 31, 2006 and 2005, respectively. As of December 31, 2006 and 2005, the Company had incurred approximately $21,556,000 (included in construction-in-process), in connection with construction of Phase II of the power plant. On January 19, 2007, the Company entered into an Amended and Restated Power Purchase Agreement and a Project Security Agreement, with KPLC with respect to Phase II of Olkaria III project. These agreements were executed after receipt of appropriate regulatory approvals from the Kenyan authorities. The construction of the second phase of the project is expected, upon completion, to add approximately 35 MW to the existing facility, bringing the project’s total capacity to approximately 48 MW. Under the Amended and Restated Power Purchase Agreement, the parties agreed to shorten

the construction period for Phase II to approximately twenty-one months commencing from the deposit of agreed collateral by KPLC, which occurred on February 7, 2007 and to reduce the tariff payable by KPLC on the total capacity of the plant upon completion of Phase II. Management believes that the project will be completed in the required timeframe. If the Company does not complete the construction of Phase II by the required date, the Company may lose some or all of its investment in the construction-in-process relating to Phase II.

ORMAT TECHNOLOGIES, INC. AND SUBSIDIARIES

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In June 1999, the Company entered into an agreement with Nicaraguan Electricity Company (‘‘NEC’’), a Nicaraguan power utility, whereby the Company will rehabilitate existing wells, drill new wells, and operate the geothermal facilities. The Company owns the plants for a fifteen-year period ending in 2014, at which time they will be transferred to NEC at no cost. The Company sells the power from the facilities to two power companies who are assignees of NEC at the agreed upon price and terms of the ‘‘take or pay’’ power purchase agreement. The net book value of the assets related to the constructed plant and wells and rehabilitated existing wells amounted to approximately $21,019,000 and $21,060,000 at December 31, 2006 and 2005, respectively. Additionally, as of December 31, 2005, the Company has incurred approximately $1,215,000 (included in construction-in-process) to drill an additional well.

As described in Note 5, during 2006, the Company increased its share in Orzunil from 21% to 100% through acquisitions. In December 1993, Orzunil entered into a twenty-year power purchase agreement (‘‘PPA’’) with Instituto Nacional de Elecrification (‘‘INDE’’). The Zunil project is located in Zunil, Guatemala. The Zunil project is comprised of one plant which commenced commercial operations in 1999 and has a generating capacity of 24 MW. According to the PPA, the geothermal resources used by the power plant are owned by INDE, which only granted the use of these resources to Orzunil for the period of the PPA. The net book value of the assets related to the power plant amounted to approximately $40,258,000 at December 31, 2006.

The Company is engaged in the construction of several geothermal power plants in other foreign countries. At December 31, 2006 and 2005, such projects were in the various stages of construction and the related costs totaling approximately $36,368,000 and $22,367,000, respectively, are included in construction-in-process.

NOTE 7 — INTANGIBLE ASSETS

Intangible assets consist mainly of all of the Company’s power purchase agreements acquired in business combinations and amounted to $50,086,000 (including royalty rights in the amount of $1,800,000) and $47,915,000 (including royalty rights in the amount of $1,800,000), net of accumulated amortization of $9,327,000 and $6,248,000 as of December 31, 2006 and 2005, respectively. Amortization expense for the years ended December 31, 2006, 2005 and 2004 amount to $3,079,000, $2,815,000 and $2,523,000, respectively.

Estimated future amortization expense for the intangible assets as of December 31, 2006 is as follows:

Year ending December 31:

	(dollars in thousands)
2007	$ 3,097
2008	3,053
2009	3,053
2010	3,053
2011	3,053
Thereafter	34,777
Total	$ 50,086

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NOTE 8 — ACCOUNTS PAYABLE AND ACCRUED EXPENSES

Accounts payable and accrued expenses consist of the following:

	December 31,	
	2006	2005
	(dollars in thousands)	
Trade payables	$ 38,524	$ 32,641
Scheduling and transmission charges	841	1,192
Royalties	595	1,143
Salaries and other payroll costs	6,514	6,186
Accrued interest	12,860	883
VAT payable	869	471
Income tax payable	5,215	4,352
Other	5,027	3,180
Total	$ 70,445	$ 50,048

NOTE 9 — LONG-TERM DEBT

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

	December 31,	
	2006	2005
	(dollars in thousands)	
Limited and non-recourse agreements:		
Non-recourse agreement:		

Senior loans:		
International Finance Corporation Loan A	$ 6,973	$ —
International Finance Corporation Loan B	3,883	—
Commonwealth Development Corporation Loan	8,530	—
Limited recourse agreement:		
Credit facility agreement	11,253	14,140
	30,639	14,140
Less current portion	(8,482)	(2,888)
Total	$ 22,157	$ 11,252
Full recourse agreements with a bank	$ 2,000	$ 3,000
Less current portion	(1,000)	(1,000)
Total	$ 1,000	$ 2,000
Senior Secured Notes (non recourse):		
Ormat Funding Corp. (‘‘OFC’’)	$ 178,693	$ 183,399
OrCal Geothermal Inc. (‘‘OrCal’’)	160,677	165,000
	339,370	348,399
Less current portion	(40,054)	(23,754)
Total	$ 299,316	$ 324,645

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Senior Loans

International Finance Corporation (‘‘IFC’’) Loan A

Orzunil, a wholly owned subsidiary of the Company, has a senior loan agreement with IFC, which was a minority shareholder of Orzunil (see also Note 5). The loan matures on November 15, 2011, and is payable in 47 quarterly installments ranging from $192,000 to $430,000. The loan has a fixed annual interest rate of 11.775%.

International Finance Corporation (‘‘IFC’’) Loan B

Orzunil has another senior loan agreement with IFC. The loan matures on May 15, 2008, and is payable in 32 quarterly installments ranging from $436,000 to $690,000. The loan has a fixed annual interest rate of 11.730%.

Commonwealth Development Corporation (‘‘CDC’’) Loan

Orzunil has a senior loan agreement with CDC, which was also a minority shareholder of Orzunil (see also Note 5). The loan matures on August 15, 2010, and is payable in 42 quarterly installments ranging from $348,000 to $675,000. The loan has a fixed annual interest rate of 10.300%.

There are various restrictive covenants under these Senior Loans, which include limitations on Orzunil’s ability to make distributions to its shareholders. Due to hurricane activity, access roads and piping from the wells to the power

plant in the Zunil Project were damaged and, consequently, the Project was not in operation from October 14, 2005 to March 10, 2006. As a result, Orzunil did not meet the historical ‘‘debt service coverage ratio’’ required and therefore, at present, distributions from the Project are restricted. As of December 31, 2006, management believes that Orzunil is in compliance with the required debt service coverage ratio and with all other covenants.

Credit Facility Agreement (the Momotombo Project)

In September 2000, Ormat Momotombo Power Company (‘‘OMPC’’), a wholly owned subsidiary of the Company, entered into a credit facility agreement with Bank Hapoalim B.M. pursuant to which OMPC executed a two-phase loan with the bank in the amounts of $11,435,000 (‘‘Phase I Loan’’) and $36,800,000 (‘‘Phase II Loan’’) (collectively the ‘‘Credit Facility Agreement’’). In March 2003, OMPC signed an amendment to the Credit Facility Agreement changing the amount of the Phase II Loan from $36,800,000 to $15,000,000. Principal and interest payments on the Phase I Loan are payable in 32 equal quarterly payments that commenced upon completion of Phase I of the project in December 2001. Interest on the Phase I Loan is variable based on 3-month LIBOR plus 2.375%. Principal and interest payments on the Phase II Loan are payable in equal 28 quarterly payments that commenced in March 2004. Interest on the Phase II Loan is variable based on 3-month LIBOR plus 3.0%, and is added to the outstanding balances of the Phase II Loan until the commencement of the principal and interest payments. At December 31, 2006 and 2005, $4,476,000 and $5,666,000, respectively, was outstanding under the Phase I Loan and $6,777,000 and $8,474,000, respectively, was outstanding under the Phase II Loan. The Credit Facility Agreement is collateralized by liens over all real and personal property comprising the Momotombo Project and the Company’s ownership interest in OMPC. There are various restrictive covenants under the Credit Facility Agreement, which include maintaining certain levels of debt to equity ratio and debt service coverage ratio, and limitations on additional indebtedness and payment of dividends. As of December 31, 2006, management believes that OMPC was in compliance with the covenants under the Credit Facility Agreement.

Full Recourse Agreements with a Bank

The Company has an $8.0 million loan agreement, with principal payable in $1 million annual installments that commenced in May 2001 and continue through May 2008. Interest is computed at 12-month LIBOR plus 1.7%, and is payable annually.

Future minimum payments

Future minimum payments under long-term obligations, excluding the senior secured notes and notes payable to Parent, as of December 31, 2006 are as follows:

Year ending December 31:	(dollars in thousands)

2007	$ 9,482
2008	8,667
2009	6,676
2010	6,101
2011	1,713
Total	$ 32,639

OFC Senior Secured Notes

On February 13, 2004, OFC, a wholly owned subsidiary, completed the issuance of $190.0 million, 8¼% Senior Secured Notes (the ‘‘OFC Senior Secured Notes’’) in an offering subject to Rule 144A and Regulation S of the Securities Act of 1933, as amended, and received net cash proceeds of approximately $179.7 million, after deduction of issuance costs of approximately $10.3 million, which have been included in deferred financing costs in the balance sheet. The OFC Senior Secured Notes have a final maturity of December 30, 2020. Principal and interest on the OFC Senior Secured Notes are payable in semi-annual payments that commenced on June 30, 2004. The OFC Senior Secured Notes are collateralized by substantially all of the assets of OFC and those of its wholly owned subsidiaries and are fully and unconditionally guaranteed by all of the wholly owned subsidiaries of OFC. There are various restrictive covenants under the OFC Senior Secured Notes, which include limitations on additional indebtedness and payment of dividends. On June 30, 2006 and December 31, 2006, OFC did not meet the ‘‘debt service coverage ratio’’ and, therefore, it is restricted from payment of dividends until it meets such ratio.

The Company has not yet granted a security interest over the new unit of the Desert Peak 2 project to the OFC Senior Secured Noteholders which is required under the indenture for the OFC Senior Secured Notes. The Company is evaluating an alternative approach to replacing the Desert Peak 1 plant with one of the new units of the Desert Peak 2 project. Implementing such an alternative would require the consent of the OFC Senior Secured Noteholders in order to ensure continued compliance with the covenants of the indenture governing the OFC Senior Secured Notes. The Company expects to launch a consent solicitation in order to amend and/or waive certain provisions of the indenture to obtain such consent from the OFC Senior Secured Noteholders. Any such solicitation will be made by means of and subject to appropriate documentation and only to the OFC Senior Secured Noteholders.

Management believes that except as described above, as of December 31, 2006, OFC is in compliance with all other covenants contained in the indenture governing the OFC Senior Secured Notes.

OFC may redeem the OFC Senior Secured Notes, in whole or in part, at any time at a redemption price equal to the principal amount of the OFC Senior Secured Notes to be redeemed plus accrued interest, premium and liquidated damages, if any, plus a ‘‘make-whole’’ premium. Upon certain events, as defined in the indenture governing the OFC Senior Secured Notes, OFC may be required to redeem a portion of the OFC Senior Secured Notes at a redemption price ranging from 100% to 101% of the principal amount of the OFC Senior Secured Notes being redeemed plus accrued interest, premium and liquidated damages, if any.

A registration statement on Form S-4 relating to the OFC Senior Secured Notes was filed with and declared effective by the SEC on February 9, 2005. Pursuant to the registration statement, OFC

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made an offer to the holders of the OFC Senior Secured Notes to exchange them for publicly registered exchange notes with substantially identical terms until March 11, 2005. On March 16, 2005 the exchange offer was completed.

On April 26, 2006, OFC successfully consummated a consent solicitation relating to the OFC Senior Secured Notes that was launched on April 17, 2006. On that same date, OFC executed a supplement to the indenture governing the OFC Senior Secured Notes to amend and/ or waive certain provisions in the indenture dealing with public reporting and information requirements of OFC. On May 1, 2006, OFC filed with the SEC Form 15 notification of the suspension of its obligation to file reports with the SEC under the Securities Act of 1934.

Debt service reserve

As required under the terms of the OFC Senior Secured Notes, OFC 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 OFC Senior Secured Notes in the following six months. This restricted cash account is classified as current on the balance sheet. As of December 31, 2006 and 2005, the balance of such account was $13.3 million and $12.3 million, respectively. In addition, as of December 31, 2006, part of the restricted cash accounts was funded by two letters of credit in the total amount of approximately $12.2 million (see Note 18).

Future minimum payments under the OFC Senior Secured Notes, as of December 31, 2006 are as follows:

Year ending December 31:	(dollars in thousands)
2007	$ 13,836
2008	7,835
2009	9,140
2010	10,118
2011	11,410
Thereafter	126,354
Total	$ 178,693

OrCal Senior Secured Notes

On December 8, 2005, OrCal, a wholly owned subsidiary, completed the issuance of $165.0 million, 6.21% Senior Secured Notes (the ‘‘OrCal Senior Secured Notes’’) in an offering subject to Rule 144A and Regulation S of the Securities Act of 1933, as amended, 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 balance sheet. The OrCal Senior Secured Notes have been rated BBB− by Fitch. The OrCal Senior Secured Notes have a final maturity of December 30, 2020. Principal and interest on the OrCal Senior Secured Notes are payable in semi-annual payments which commenced on June 30, 2006. 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 and payment of dividends. Management believes that as of December 31, 2006, OrCal was in compliance with the covenants under the OrCal Senior Secured Notes.

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

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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, with a required minimum balance, 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 OrCal Senior Secured Notes in the following six months. This restricted cash account is classified as current on the balance sheet. As of December 31, 2006 and 2005, the balance of such account was $14.8 million and $9.5 million, respectively. In addition, as of December 31, 2006, part of the restricted cash accounts was funded by a letter of credit in the amount of approximately $9.7 million (see Note 18).

Future minimum payments under the OrCal Senior Secured Notes, as of December 31, 2006 are as follows:

Year ending December 31:	(dollars in thousands)
2007	$ 26,218
2008	17,641
2009	11,043
2010	10,216
2011	9,700
Thereafter	85,859
Total	$ 160,677

In anticipation of the OrCal Offering, on September 9, 2005, the Company entered into a rate lock agreement with a financial institution (the ‘‘counterparty’’), at a locked-in rate of 4.047%, with a notional amount of $175.0 million, which terminated on December 5, 2005. The rate lock was based on a 7-year treasury security that matures in November 2012. On December 5, 2005, the Company received from the counterparty to the rate lock agreement an amount of $4,488,000. A gain of $2,624,000, net of related taxes of $1,608,000, is recorded as ‘‘Gain in respect of derivative instruments designated for cash flow hedge, net of related taxes’’ under ‘‘Other comprehensive income (loss)’’ and is amortized over the term of the OrCal Senior Secured Notes using the effective interest method. The remaining gain of $159,000, net of related taxes of $97,000, has been charged to the consolidated statement of operations ($256,000 has been recorded as interest income and $97,000 has been recorded as income tax expense).

In December 2003, in connection with the acquisition of the Heber power plants, OrCal entered into a loan agreement with Beal Bank (‘‘Beal Bank Credit Agreement’’) to provide a loan in the amount of $154.5 million. On December 8, 2005, in connection with the issuance of the OrCal Senior Secured Notes, OrCal repaid the loan in its entirety. This repayment resulted in a one-time charge to interest expense of approximately $16.6 million, comprised of: (i) prepayment premium of $11.5 million associated with payment of the Beal Bank loan, (ii) write-off of certain deferred financing costs amounting to $4.2 million associated with the incurrence of the Beal Bank loan, and (iii) loss of $0.9 million associated with the interest rate caps transaction described below. The tax effect of such one time charge is $6.3 million, bringing the net effect of it to $10.3 million.

During the second quarter of 2004, the Company entered into two separate interest rate cap agreements (‘‘Cap Transactions’’) with two different financial institutions to mitigate the interest rate

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risk associated with the Beal Bank Credit Agreement. Pursuant to the Cap Transactions, the Company paid an aggregate of $3,820,000 to the financial institutions. The Cap Transactions are effective as of March 30, 2007 and terminate on March 31, 2011. Pursuant to the terms of the Cap Transactions, the financial institutions providing the cap are required to pay to the Company the difference between the 3-month LIBOR rate and 6.0%, (if LIBOR is greater than 6.0%), times the notional amount, which for each of the contracts will be $67,401,000 on the effective date and reduces each payment period down to $49,633,000 upon termination. From October 1, 2004 to December 8, 2005 (the date of the repayment of the Beal Bank Loan), the Cap Transactions qualified for cash flow hedge accounting. The fair value of the Cap Transactions at December 31, 2005 and 2004 amounted to $1,034,000 and $1,663,000, respectively. The decrease in the fair value for the period from the initiation of the Cap Transactions through September 30, 2004 of $1,637,000 has been recorded in the consolidated statement of operations as interest expense, while the decrease in the fair value for the period from October 1, 2004 to December 31, 2004 of $322,000, net of related taxes of $198,000 was included as ‘‘Loss in respect of derivatives instruments designated for cash flow hedge, net of related taxes’’ under ‘‘Other comprehensive income (loss)’’. The decrease in the fair value for the period from January 1, 2005 to December 8, 2005 (the date of the repayment of the Beal Bank loan) of $241,000, net of related taxes of $149,000, was included in ‘‘Other comprehensive income (loss)’’. As a result of the early repayment of the Beal Bank loan, the aggregate amount of $563,000, net of related taxes of $347,000, which was included in ‘‘Other comprehensive income (loss)’’, has been charged to the consolidated statement of operations ($910,000 have been recorded as interest expense and $347,000 have been recorded as income tax benefit), and the decrease in the fair value for the period from December 8, 2005 to December 31,2005 of $239,000 has been recorded in the consolidated statement of operations as interest expense. The decrease in the fair value for the year ended December 31, 2006 of $559,000 has been recorded in the consolidated statement of operations as interest expense. The fair value of the Cap Transactions is the estimated amount that the Company would currently pay to terminate the transactions at the reporting date, taking into account current interest rates and the current creditworthiness of the counterparties to the agreements.

NOTE 10 — PUNA PROJECT LEASE TRANSACTIONS

On May 19, 2005, the Company's wholly owned subsidiary in Hawaii, Puna Geothermal Ventures (''PGV'') entered into a transaction involving the Puna geothermal power plant located on the Big Island of Hawaii (the ''Puna Project''), which was acquired in June 2004. A similar transaction relating to two new geothermal wells that PGV drilled in the second half of 2005 (for production and injection) was completed on December 30, 2005.

Pursuant to a 31-year head lease (the ''Head Lease''). PGV leased its geothermal 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, 2006 and 2005 amounted to $56.0 million and $58.3 million, net of accumulated depreciation of $6.4 million and $3.7 million, respectively. The unrelated company (the ''Lessor'') simultaneously leased back the Puna Project 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 Project under a power purchase agreement that PGV has with Hawaii Electric Light Company (''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 power purchase agreement 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 SFAS No. 13, Accounting 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 $4.3 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, 2006, are as follows:

Year ending December 31:	(dollars in thousands)
2007	$ 9,742
2008	7,573
2009	8,013
2010	7,567
2011	8,061
Thereafter	72,126
Total	$ 113,082

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 are included in the balance sheet as of December 31, 2006 and 2005 in restricted cash accounts and are classified as current as they are used for

current payments.

Revenue account

PGV deposits all revenues received into the revenue account. Such amounts are used to pay operating expenses and fund the depository accounts as describe below, but the funds are only available to PGV upon submission of draw requests by PGV to the bank. As such amounts are fully restricted to use by PGV, they have been classified as current restricted assets as the amounts are used to pay current operating expenses. As of December 31, 2006 and 2005, the balance of such account was $2.7 million and $3.5 million, respectively.

Lease rent reserve accounts

PGV maintains accounts to fund the full amount of the next rent payment according to the payment schedule. As of December 31, 2006 and 2005, the balance of such accounts was $6.2 million and $2.3 million, respectively.

Well maintenance reserve account

PGV maintains a reserve account to fund well field works including the drilling of new wells. The reserve should be met on a monthly basis, in amounts equal to 1/12 of a scheduled annual contribution. As of December 31, 2006 and 2005, the balance of such account was $0.2 million and $0.5 million, respectively.

Capital expenditure account

PGV maintains an account to fund its capital expenditures. Deposits to this account are at PGV's sole discretion, but no distributions are allowed to Ormat Nevada Inc., a wholly owned subsidiary of the Company that is the indirect parent of PGV, if the balance is less than $0.5 million. As of December 31, 2006 and 2005, the balance in this account was $0.5 million and $0, respectively.

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 Inc. The distributions are allowed only if PGV maintains various restrictive covenants

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under the lease agreements, which include limitations on additional indebtedness. As of December 31, 2006 and 2005, the balance of such account was $11.3 million and $6.8 million, respectively. This amount can be distributed to Ormat Nevada Inc. currently and has been classified as current restricted assets.

In anticipation of the above lease transactions, on February 25, 2005, the Company entered into a treasury rate lock agreement with a financial institution, at a locked-in treasury rate of 4.31%, with a notional amount of $52.0 million,

which terminated on March 31, 2005. The rate lock was based on a 10-year treasury security that matures on February 15, 2015. On March 31, 2005, the Company received from the counterparty to the rate lock agreement an amount of $658,000. This amount, net of related taxes of $250,000, is recorded as ‘‘Gain in respect of derivative instruments designated for cash flow hedge, net of related taxes’’ under ‘‘Other comprehensive income (loss)’’ and is amortized over the 23-year term of the Project Lease.

On April 20, 2005, the Company entered into a new treasury rate lock agreement with the same financial institution, at a locked-in treasury rate of 4.22%, with a notional amount of $52.0 million and originally scheduled to terminate on May 2, 2005. The new rate lock agreement’s termination date was extended until May 18, 2005 at a new locked-in treasury rate of 4.25%. The rate lock was based on a 10-year treasury security that matures on February 15, 2015. There was no consideration paid by either party as a result of the extension. On May 18, 2005, the Company paid the counterparty to the new rate lock agreement the amount of $762,000. This amount, net of related taxes of $290,000, is recorded in ‘‘Other comprehensive income (loss)’’ and is amortized over the 23-year term of the Project Lease.

NOTE 11 — 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:

	December 31,	
	2006	2005
	(dollars in thousands)	
Balance at beginning of period	$ 11,461	$ 10,665
Changes in price estimates	4,400	22
Accretion expense	971	774
Balance at end of period	$ 16,832	$ 11,461

During the fourth quarters of 2006 and 2005, the Company increased the aggregate carrying amount of its asset retirement obligation by $4,400,000 and $22,000, respectively. The net increase is a result of increased costs associated with drilling rigs, cement and cement services, general manpower, engineering fees and other outside services since the adoption of SFAS No. 143.

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NOTE 12 — STOCK-BASED COMPENSATION

Effective January 1, 2006, the Company adopted SFAS No. 123R which establishes the accounting for employee stock-based awards. Under the provisions of SFAS No. 123R, stock-based compensation 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). The Company adopted SFAS No. 123R using the modified

prospective method. Under this method, prior periods are not restated and the amount of compensation cost recognized includes (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, and (ii) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123R. SFAS No. 123R requires unrecognized cost, based on the amounts previously disclosed in the Company's pro forma footnote disclosure, related to options vesting after the date of initial adoption to be recognized in the financial statements over the remaining requisite service period. The provisions of SFAS No. 123R apply to new stock awards and stock awards outstanding, but not yet vested, on the effective date. In March 2005, the SEC issued Staff Accounting Bulletin No. 107 (''SAB No. 107'') relating to SFAS No. 123R. The Company has applied the provisions of SAB No. 107 in its adoption.

Impact of the adoption of SFAS No. 123R

Upon adoption of SFAS No. 123R, the Company recognizes share-based compensation expenses associated with share awards on a straight-line basis over the requisite service period using the fair value method. The incremental share-based compensation expense recognized due to the adoption of SFAS 123R was $1.7 million for the year ended December 31, 2006.

As required by SFAS No. 123R, the Company made an estimate of expected forfeitures and is recognizing compensation costs only for those equity awards expected to vest. The cumulative effect of initially adopting SFAS No. 123R is not material. As of December 31, 2006, the total future compensation cost related to unvested stock options that are expected to vest is $4,023,503 which will be recognized over a weighted average period of 2.94 years.

During the year ended December 31, 2006 the Company recorded stock-based compensation related to stock options as follows:

	(In thousands, except per share data)
Cost of Revenues	$ 798
Selling and marketing expenses	287
General and administrative expenses	621
Total stock-based compensation expense	1,706
Tax effect on stock-based compensation expense	239
Net effect on stock-based compensation expense	$ 1,467
Effect on basic and diluted earnings per share	$ 0.04

Pro forma information for periods prior to the adoption of SFAS No. 123R

Prior to January 1, 2006, the Company accounted for stock-based compensation in accordance with the provisions of Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (''APB No. 25''), and related interpretations. Under APB No. 25, compensation cost was

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recognized based on the difference, if any, on the date of grant between the fair value of the Company's stock and the amount an employee must pay to acquire the stock.

SFAS No. 123R requires disclosure of pro forma information for periods prior to the adoption. The pro forma disclosures are based on the fair value of awards at the grant date, amortized to expense over the service period. The following table illustrates the effect on net income and earnings per share as if the Company had applied the fair value recognition provisions of SFAS No. 123 for the period prior to the adoption of SFAS No. 123R and the actual effect on net income and earnings per share for the period after the adoption of SFAS No. 123R.

	Year ended December 31,		
	2006	2005	2004
	(dollars in thousands, except per share data)		
Net income, as reported	$ 34,447	$ 15,177	$ 17,791
Add: Total stock-based employee compensation expense included in reported net income, net of tax	1,467	91	61
Deduct: Total stock-based employee compensation expense in respect of the Company's stock options determined under fair value based method, net of tax	(1,166)	(65)	(6)
Deduct: Total stock-based employee compensation expense in respect of the Parent's stock options determined under fair value based method, net of tax	(301)	(307)	(685)
Pro forma net income	$ 34,447	$ 14,896	$ 17,161
Earnings per share:			
Basic, as reported	$ 1.00	$ 0.48	$ 0.72
Basic, pro forma	$ 1.00	$ 0.47	$ 0.69
Diluted, as reported	$ 0.99	$ 0.48	$ 0.72
Diluted, pro forma	$ 0.99	$ 0.47	$ 0.69

The fair value of each option grant is estimated using the Black-Scholes valuation model and the assumptions noted in the following table. The Company's expected term represents the period that the Company's stock-based awards are expected to be outstanding. In the absence of enough historical information, the expected term was determined using the simplified method'' defined in SAB No. 107, giving consideration to the contractual term and vesting schedule. Since the Company does not have any traded stock options and was listed for trading on the New York Stock Exchange beginning in November 2004, the Company's expected volatility was calculated based on the Company's historical volatility and for the period of time prior to the Company's listing, the historical volatility of the Parent. There is a high correlation between the stock behavior of the Company and its Parent. The dividend yield forecast is expected to be 20% of the Company's yearly net profit, which is equivalent to a 0.55% yearly dividend rate. The risk free interest rate was based on the yield from U.S. constant treasury maturities bonds with an equivalent term. The forfeiture rate of 5% is based on trends in actual option forfeitures.

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The Company calculated the fair value of each option on the date of grant based on the following assumptions:

	Year Ended December 31,		
	2006	2005	2004
For stock options issued by the Company:			
Risk-free interest rates	4.9%	4.5%	3.6%
Expected lives (in years)	6.4	5.0	5.0
Dividend yield	0.55%	0.9%	4.0%
Expected volatility	40.5%	32.0%	40.0%
Forfeiture rate	5.0%	—	—
For stock options issued by the Parent:			
Risk-free interest rates	—	—	4.7%
Expected lives (in years)	—	—	5.0
Dividend yield	—	—	0%
Expected volatility	—	—	28%

Stock Option Plans

The 2004 Incentive Compensation Plan

On October 21, 2004, the Company's Board of Directors adopted the 2004 Incentive Compensation Plan (''2004 Incentive Plan''), which provides for the grant of the following types of awards: incentive stock options, non-qualified stock options, restricted stock, stock appreciation rights, stock units, performance awards, phantom stock, incentive bonuses and other possible related dividend equivalents to employees of the Company, directors and independent contractors. Under the 2004 Incentive Plan, a total of 1,250,000 shares of the Company's common stock have been reserved for issuance, all of which could be issued as options or as other forms of awards. Options granted to employees under the 2004 Incentive Plan cliff vest and are exercisable from the grant date as follows: 25% after 24 months, 25% after 36 months, and the remaining 50% after 48 months. Options granted to non-employee directors under the 2004 Incentive Plan cliff vest and are exercisable one year after the grant day. Vested shares may be exercised for up to ten years from the date of grant. On November 9, 2005, the Company filed a registration statement on Form S-8 with the SEC with respect to the shares of common stock underlying such grants. The shares of common stock will be issued upon exercise of options from the Company's authorized share capital.

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On February 27, 2006 the Company's Board of Directors approved an increase of the total number of shares of the Company's common stock which have been reserved for issuance to 3,750,000, subject to stockholder approval. The following table summarizes the status of the 2004 Incentive Plan as of and for the periods presented below (shares in thousands):

	Year Ended December 31, 2006		Year Ended December 31, 2005		Year Ended December 31, 2004	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	236	$ 15.54	223	$ 15.00	—	$ —
Granted, at fair value	329	34.47	25	20.10	223	15.00
Exercised	(14)	15.00	—	—	—	—
Forfeited	(12)	20.25	(12)	15.00	—	—
Outstanding at end of year	539	27.03	236	15.54	223	15.00
Options exercisable at end of year	72	16.76	15	15.00	—	
Weighted-average fair value of options granted during the year		$ 15.77		$ 6.62		$ 0.96

As of December 31, 2006, 696,900 shares of the Company's common stock are available for future grants.

The following table summarizes information about stock options outstanding at December 31, 2006 (shares in thousands):

	Options Outstanding			Options Exercisable		
Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)	Number of Shares Exerciseble	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)
$15.00	188	7.8	$ 4,094	47	7.8	$ 1,035
20.10	25	7.8	418	25	7.8	418
34.13	296	9.3	797	—	—	—
37.90	30	6.8	—	—	—	—
	539	8.6	$ 5,309	72	7.8	$ 1,453

The following table summarizes information about stock options outstanding at December 31, 2005 (shares in

thousands):

	Options Outstanding			Options Exercisable		
Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)	Number of Shares Exerciseble	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)
$15.00	211	8.8	$ 2,348	15	8.8	$ 167
20.10	25	8.8	151	—	—	—
	236	8.8	$ 2,499	15	8.8	$ 167

The aggregate intrinsic value in the above tables represents the total pretax intrinsic value, based on the Company's stock price of $36.82 as of December 31, 2006, which would have potentially been

received by the option holders had all option holders exercised their options as of that date. The total number of in-the-money options exercisable as of December 31, 2006 was 72,426.

The total pretax intrinsic value of options exercised during the year ended December 31, 2006 was $331,000 based on the Company's average stock price of $38.12 during the year ended December 31, 2006.

The Parent's Stock Option Plans

The Parent has four stock option plans: the 2001 Employee Stock Option Plan, the 2002 Employee Stock Option Plan, the 2003 Employee Stock Option Plan, and the 2004 Employee Stock Option Plan (collectively ''the Parent's Plans''). Options under the 2004 Employee Stock Option Plan were granted in April 2004. Under the Parent's Plans, employees of the Company were granted options in the Parent's ordinary shares, which are registered and traded on the Tel-Aviv Stock Exchange. Options under the Parent's Plans cliff vest and are exercisable from the grant date as follows: 25% after 24 months, 25% after 36 months, and the remaining 50% after 48 months. Vested shares may be exercised for up to five years from the date of grant. The maximum aggregate number of shares that may be optioned and sold under the Parent's Plans is determined each year by the board of directors of the Parent, and is equal to the number of options granted during each plan year. None of the options are exercisable or convertible into shares of the Company.

As of December 31, 2006, no shares of the Parent's ordinary shares are available for future grants.

The following table summarizes the status of the Parent's Plans as of and for the periods presented below (shares in thousands):

	Year Ended December 31, 2006		Year Ended December 31, 2005		Year Ended December 31, 2004	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	1,747	$ 2.42	2,362	$ 2.32	1,930	$ 1.81
Granted, below fair value	—	—	—	—	651	3.78
Exercised	(560)	1.81	(554)	1.97	(192)	1.97
Expired	(32)	2.26	—	—	—	—
Forfeited	(57)	2.96	(61)	2.62	(27)	2.00
Outstanding at end of year	1,098	2.70	1,747	2.42	2,362	2.32
Options exercisable at end of year	322	$ 2.23	296	1.79	215	1.88
Weighted-average fair value of options granted during the year		$ —		$ —		$ 1.73

The Company recorded in the year ended December 31, 2004, deferred stock compensation of $52,000 for options granted below fair market value. This balance represents the difference between the exercise price of the options and the fair market value of the Parent's shares on the date of grant. Prior to January 1, 2006, the deferred stock compensation has been amortized to expense over the vesting period. The amortization of deferred stock compensation for the years ended December 31, 2005 and 2004 is $91,000 and $61,000, respectively.

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The following table summarizes information about stock options outstanding at December 31, 2006 (shares in thousands):

	Options Outstanding			Options Exercisable		
Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)	Number of Shares Exerciseble	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)
$1.41	111	0.2	$ 1,105	111	0.2	$ 1,105
1.75	453	1.2	4,357	116	1.2	1,118
3.78	534	2.3	4,056	95	2.3	721

1,098	1.6	$ 9,518	322	1.2	$ 2,944

The following table summarizes information about stock options outstanding at December 31, 2005 (shares in thousands):

	Options Outstanding			Options Exercisable		
Exercise Price	Number of Shares Outstanding	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)	Number of Shares Exerciseble	Weighted Average Remaining Contractual Life in Years	Aggregate Intrinsic Value (In thousands)
$1.41	379	1.2	$ 2,282	67	1.2	$ 405
1.75	681	2.2	3,864	161	2.2	915
2.26	68	0.1	349	68	0.1	349
3.78	619	3.3	2,257	—	—	—
	1,747	2.3	$ 8,752	296	1.5	$ 1,669

The aggregate intrinsic value in the above tables represents the total pretax intrinsic value, based on the Parent's stock price of $11.37 as of December 31, 2006, which would have potentially been received by the option holders had all option holders exercised their options as of that date. The total number of in-the-money options exercisable as of December 31, 2006 was 322,179.

The total pretax intrinsic value of options exercised during the year ended December 31, 2006 was $4,328,000 based on the Parent's average stock price of $9.48 during the year ended December 31, 2006.

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NOTE 13 — POWER PURCHASE AGREEMENTS

U.S. operations:

The Company has various power purchase agreements in the U.S. as follows:

Southern California Edison Company (''SCE'') — California

The Company has two power purchase agreements (''PPAs'') with SCE related to the Ormesa Complex and two PPAs related to the Heber 1 and 2 projects. The PPAs provide for the sale of capacity and energy through their respective terms, with the following expiration dates: Ormesa PPAs expire in 2017 and 2018, and Heber 1 and 2 PPAs expire in 2015 and 2023, respectively. Under the PPAs, the Company receives a fixed energy payment through April 30, 2012,

and thereafter an energy payment based on SCE's short-run avoided cost (''SRAC''). The PPAs provide for firm capacity and bonus payments established by the contracts and are paid to the Company each month through the contracts' term based on plant performance. Bonus capacity payments are earned based on actual capacity available during certain peak hours. In certain circumstances, SCE or its designee has a right of first refusal to acquire the OG I and OG II power plants in the Ormesa project and the Heber 1 power plant at fair market value. Upon satisfaction of certain conditions specified in the PPA and subject to receipt of requisite approvals and negotiations between the parties, the Company will have the right to demand that SCE purchase the Heber 1 power plant at fair market value.

In connection with the power purchase agreements for the Ormesa project, SCE has expressed its intent not to pay the contract rate for the power supplied by the GEM 2 and GEM 3 plants to the Ormesa project. SCE contends that California ISO real-time prices should apply, while management believes that SP-15 prices quoted by NYMEX should apply. According to SCE's estimation, the amount under dispute is approximately $2.5 million. The parties have signed an Interim Agreement; whereby SCE will continue to procure the GEM 2 and GEM 3 power at the current energy rate of 5.37 cents/kWh until May 1, 2007. In addition a long-term PPA is expected to be entered into for the GEM 2 and GEM 3 power. The negotiations of the long-term PPA are still under way and there is no guarantee that it will be successfully completed. Management believes that such settlement agreement will not have a material financial impact on the Company. Therefore, no provision is included in the financial statements in respect of the dispute.

Sierra Pacific Power Company (''SPPC'') — Nevada

The Company has seven PPAs with SPPC for operating projects; one related to the Brady power plant, two related to the Steamboat 1 and 1A power plants, one related to the Steamboat Hills power plant, two related to the Steamboat 2 and 3 power plants and one related to the Burdette power plant. The Burdette PPA provides for the sale of energy and will expire in 2026. All the other PPAs provide for the sale of energy, and for capacity for all power plants except Brady, through their respective terms, with the following expiration dates: Steamboat 1 and 1A expire in 2007 (see below) and 2018, Steamboat Hills expires in 2018, and Brady and Steamboat 2 and 3 expire in 2022. Energy payments under the Brady PPA are based on deliveries during specified winter and summer seasons for on-peak, mid-peak, and off-peak times. Energy payments under the Steamboat 1/1A PPAs are based on the monthly average of the California-Oregon Border power market pricing, which is SPPC's adopted SRAC. The Steamboat 1 PPA expired at the end of 2006, but the Company continues to sell electricity by an automatic extension of the PPA on a year-by-year basis.

Hawaii Electric Light Company (''HELCO'') — Hawaii

The Company has a PPA with HELCO related to the Puna project. The PPA provides for monthly energy payments and capacity payments. The energy payments for a portion of the energy delivered are equal to the higher of the SRAC rates for energy in effect for the relevant billing period

or a fixed rate. The energy payments for a smaller portion of energy to be delivered are equal to an amount based on a fuel rate and a variable operation and maintenance rate, as each are adjusted over the term of the agreement, but which rate will never go below a minimum floor. The Puna project also receives a payment for providing reactive power to HELCO.

Southern California Public Power Authority (‘‘SCPPA’’) — California

The Company has a 25-year PPA with SCPPA for the sale of energy from the Gould plant in the Heber complex. Under the Gould PPA, 10 MW of power will be delivered to SCPPA for a fixed price which will escalate annually at a rate of 1.5% and includes the value for the environmental attributes, known as renewable energy credits. Deliveries began in the second quarter of 2006.

Nevada Power Company (‘‘Nevada Power’’) — Nevada

The Company has a 25-year PPA with Nevada Power for the sale of energy from the Desert Peak 2 project for a fixed price. Commercial operation of the Desert Peak 2 project has not yet been declared.

Foreign operations:

The Company has power purchase agreements in various foreign countries as follows:

The Olkaria III Project (Kenya)

In connection with the agreement with KPLC (see Note 6), the subsidiary in Kenya, sells power to KPLC at the agreed upon price and terms of a 20-year PPA. Fees are paid each month through the term of the agreement and vary based on plant performance.

The Momotombo Project (Nicaragua)

In connection with the agreement with NEC (see Note 6), the subsidiary in Nicaragua sells power to two assignees of NEC at the agreed upon price and terms of a ‘‘take or pay’’ PPA. Fees are paid each month through the term of the PPA and vary based on plant performance.

The Zunil Project (Guatemala)

In connection with the agreement with INDE (see Note 6), the subsidiary in Guatemala sells power to INDE at the agreed upon price and terms of a 20-year ‘‘take or pay’’ PPA. The PPA provides for monthly minimum energy payments and capacity payments, based on demonstrated capacity. Fees are paid each month through the term of the PPA.

Additional information

Pursuant to the terms of certain of the power purchase agreements, the Company may be required to make payments to the relevant power purchaser under certain conditions, such as shortfall on delivery of renewable energy and energy credits, and not meeting certain threshold performance requirements, as defined. The amount of payment required is dependent upon the level of shortfall on delivery or performance requirements and is recorded in the period the shortfall occurs.

The Brady and Steamboat 2 and 3 PPAs provide that if the project does not maintain peak period capacity values of at least 85% of those listed in each of their respective contracts, the Company will be obligated to pay liquidated damages to SPPC in amounts ranging from $1.0 million to $1.5 million.

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If the Ormesa and Heber 1 and 2 projects fail to meet minimum performance requirements, as defined, the respective project may be placed on probation, the capacity of the relevant plant may be permanently reduced and, in such an instance, a refund would be owed from such project to SCE. Each of the projects may also reduce the capacity of the plants upon notice to SCE and after making a specified payment to it. During 2006, the Company experienced a relatively high rate of well and pump failure at the Ormesa project resulting in a lower availability of the Ormesa well field. As a result, the Ormesa project did not meet the required minimum capacity factor of 80% during the on-peak period for the month of September 2006. Consequently, the Ormesa project has been placed on probation for a period not to exceed 15 months. During the probation period, if the Ormesa project fails again to meet the minimum performance requirements, the capacity of the project may be permanently reduced, in which case SCE would be entitled to a refund. Management believes that the risk of not meeting the requirements during the probation period and in the future is very low.

If the Puna project does not meet its minimum capacity performance requirement, such project will be required to pay HELCO $0.0214 per on-peak hour for each kilowatt of deficiency for the first 5 MW of deficiency and $0.0339 per on-peak hour for each kilowatt of deficiency in excess of 5 MW of deficiency. In addition, for each contract year in which the on-peak availability of the facility is less than 95%, unless the deficiency is due to a catastrophic equipment failure, the Puna project is required to pay $8,000 to HELCO for each full percentage point of the deficiency, and if such availability is less than 80%, the Puna project is required to pay $12,000 for each full percentage point of the deficiency.

The Company has not and does not currently expect to be obligated to make any material payments under its power purchase agreements.

As required by EITF Issue No. 01-8 (see Note 1), the Company assessed all PPAs agreed to, modified or acquired in business combinations on or after July 1, 2003, and concluded that all such PPAs contained a lease element requiring lease accounting. Accordingly, revenue related to the lease element of the PPA is presented as ‘‘lease portion of energy and capacity’’ revenue, with the remaining revenue related to the production and delivery of the energy being presented as ‘‘energy and capacity’’ revenue in the consolidated statements of operations. Future minimum lease revenues under PPAs which contain a lease element as of December 31, 2006 were as follows:

Year ending December 31:	(dollars in thousands)
2007	$ 109,695
2008	112,268
2009	105,830
2010	103,518
2011	101,965
Thereafter	1,276,085

Total	$ 1,809,361

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NOTE 14 — INCOME TAXES

Income from continuing operations before provision for income taxes, minority interest, and equity in income of investees consisted of:

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
U.S	$ 14,306	$ 702	$ 8,436
Non-U.S. (foreign)	23,211	12,271	12,505
	$ 37,517	$ 12,973	$ 20,941

The components of income tax expense are as follows:

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Current:			
Federal	$ —	$ —	$ —
Foreign	7,931	6,872	2,824
	$ 7,931	$ 6,872	$ 2,824
Deferred:			
Federal	$ 157	$ 577	$ 2,772
State	304	132	86
Foreign	(1,989)	(2,891)	927
	(1,528)	(2,182)	3,785
	$ 6,403	$ 4,690	$ 6,609

The significant components of the deferred income tax expense are as follows:

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		

Deferred tax expense (exclusive of the effect of other components listed below)	$ 8,272	$ 10,089	$ 6,433
Benefit of operating loss carryforwards — US	(4,341)	(1,923)	(3,575)
Utilization of operating loss carryforwards — Israel	—	—	796
Change in valuation allowance	—	—	(796)
Change in foreign income tax	(1,989)	(2,891)	927
Change in lease transaction	1,236	(7,457)	—
Benefit of production tax credits	(4,706)	—	—
	$ (1,528)	$ (2,182)	$ 3,785

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The difference between the U.S. federal statutory tax rate and the Company's effective rate are as follows:

	Year Ended December 31,		
	2006	2005	2004
U.S. federal statutory tax rate	34.0%	34.0%	34.0%
State income tax, net of federal benefit	0.8	0.7	0.3
Effect of foreign income tax, net	(7.0)	(1.5)	(2.4)
Production tax credit	(12.5)	—	—
Other, net	1.8	3.0	(0.3)
Effective tax rate	17.1%	36.2%	31.6%

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

	December 31,	
	2006	2005
	(dollars in thousands)	
Deferred tax assets (liabilities):		
Net foreign deferred taxes, primarily depreciation	$ (3,574)	$ (5,563)
Depreciation	(42,215)	(33,840)
Net operating loss carryforward — U.S.	17,184	12,843
Lease transaction	6,221	7,457
Investment tax credits	1,971	1,971
Production tax credits	4,706	—
Stock options amortization	239	—
Accrued liabilities and other	1,785	2,167
Total	$ (13,683)	$ (14,965)

Deferred taxes are included in the balance sheets as follows:

	December 31,	
	2006	2005
	(dollars in thousands)	
Among current assets	$ 1,819	$ 1,663
Among non-current assets	6,172	5,376
Among non-current liabilities	(21,674)	(22,004)
	$ (13,683)	$ (14,965)

Realization of the deferred tax assets and tax credits is dependent on generating sufficient taxable income prior to expiration of the net operating loss (‘‘NOL’’) carryforwards and tax credits. Although realization is not assured, management believes it is more likely than not that the deferred tax asset at December 31, 2006 will be realized.

At December 31, 2006, the Company had U.S. federal NOL carryforwards of approximately $46.5 million and state NOL carryforwards of approximately $39.3 million, available to reduce future taxable income, which expire between 2021 and 2025 for federal NOLs and between 2014 and 2016 for state NOLs. The investment tax credits in the amount of $2.0 million at December 31, 2006 are available for a 20-year period and expire in 2022 and 2023. The production tax credits in the amount of $4.7 million at December 31, 2006 are available for a 20-year period and expire in 2025.

Through June 30, 2004, the Company had NOL carryforwards related to its Israeli operations of approximately $14.0 million available to reduce future taxable income, which could be carried over

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indefinitely until utilized. However, despite the fact that the NOL carryforward period was indefinite, there is currently uncertainty as to the Israeli tax laws related to establishing limitations on the use of NOLs. In addition, there are uncertainties as to the ability to transfer those losses from the Parent. Due to these uncertainties, management reached the conclusion that it was not likely that such NOL carryforwards will be utilized. Subsequent to July 1, 2004, it was determined that the losses could not be transferred; therefore, the deferred tax assets in respect of the Parent’s NOL carryforwards and the valuation allowance relating to such deferred tax assets were removed.

The total amount of undistributed earnings of foreign subsidiaries for income tax purposes was approximately $78.0 million at December 31, 2006. It is the Company’s intention to reinvest undistributed earnings of its foreign subsidiaries and thereby indefinitely postpone their remittance. Accordingly, no provision has been made for foreign withholding taxes or U.S. income taxes which may become payable if undistributed earnings of foreign subsidiaries were paid as dividends to the Company. The additional taxes on that portion of undistributed earnings which is available for dividends are not practicably determinable.

Tax benefits in the U.S.

The U.S. federal government encourages production of electricity from geothermal resources through certain tax subsidies. The Company is permitted to claim in its consolidated federal tax returns either an investment tax credit for approximately 10% of the cost of each new geothermal power plant or ‘‘production tax credits’’, which in 2006 were 1.9 cents per kWh and is adjusted annually for inflation, on the first ten years of electricity output, under the Energy Policy Act of 2005 that became law on August 8, 2005. (Production tax credits can only be claimed on new plants put into service between October 23, 2004 and December 31, 2008.) The Company, as the owner of any project that would be put in service during the period ending December 31, 2008, has to choose between the production tax credit and the investment tax credit.

Certain of the Company’s power purchase agreements that were in effect as of December 31, 2006 provide that all or a portion of the production tax credits are to be shared with the utility once they are monetized from the federal government. The Company has the ability to elect investment tax credits rather than production tax credits in its federal tax returns. Given the existing power purchase agreements, the Company would be economically compelled to elect investment tax credits for certain facilities thereby eliminating any amounts that would be due to the utilities under the production tax credit sharing arrangement. As such, the Company has not deferred revenue for such arrangements. The Company is in the process of negotiating the elimination of the production tax credit sharing provisions in exchange for a prospective reduction in the energy rate. Subsequent to December 31, 2006, the Company finalized one such amendment. Based upon negotiations to date and the expectations of the Company, the Company believes it is likely that the remaining power purchase agreements will be similarly modified. As a result, the Company has not anticipated the investment tax credits for purposes of its 2006 tax provision.

Income taxes related to foreign operations

The Philippines — From OLCL’s inception in 1996 to September 2003, OLCL, an 80% owned subsidiary (which was deconsolidated as of April 1, 2004) with operations in the Philippines, had an income tax holiday. Subsequent to September 2003, OLCL is subject to the Philippines regular corporate income tax rate of 32%.

Guatemala — The enacted tax rate is 31%. The Company was granted a benefit under a law which promotes development of renewable power sources. The law allows the Company to reduce the investment made in its geothermal project from income tax payable, which brings the effective tax rate to zero.

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Israel — The Company’s operations in Israel through OSL are taxed at the regular corporate tax rate of 36% in 2003, 35% in 2004, 34% in 2005, 31% in 2006, 29% in 2007, 27% in 2008, 26% in 2009 and 25% in 2010 and thereafter. OSL received from Israel’s Investment Center ‘‘Approved Enterprise’’ status under Israel’s Law for Encouragement of Capital Investments, 1959 (the ‘‘Investment Law’’), with respect to two of its investment programs. One such approval was received in 1996 and the other was received in May 2004. In respect of the approval from 1996, OSL has utilized all the tax benefits it was entitled to. Recently, due to a broad legislative amendment in the Investment Law, OSL replaced the certificate approval received in May 2004 from Israel’s Investment Center with a ruling from the Israeli

Tax Authorities. The ruling was obtained in April 2006. By replacing the certificate of approval with a ruling, OSL maximized the tax benefits it is entitled to under the Investment Law. As an Approved Enterprise and according to the ruling, OSL was exempt from Israeli income taxes with respect to income derived from the approved investment for the years 2004 and 2005 and thereafter such income is subject to reduced Israeli income tax rates of 25% for an additional five years. These benefits are subject to certain conditions set forth in the ruling, including among other things, that all transactions between OSL and its affiliates are at arms length, and that the management and control of OSL will be from Israel during the whole period of the tax benefits. A change in control should be reported to the Israeli Tax Authorities in order to maintain the tax benefits. In addition, as an industrial company, OSL is entitled to accelerated depreciation on equipment used for its industrial activities.

Other significant foreign countries — The Company's operations in Nicaragua and Kenya are taxed at the rates of 25% and 37.5%, respectively.

NOTE 15 — BUSINESS SEGMENTS

The Company has two reporting segments that are aggregated based on similar products, market and operating factors: electricity and products segments. Such 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 pursuant to power purchase agreements. The products segment is engaged in the manufacture, including design and development, of turbines and power units for the supply of electrical energy and in the associated construction of power plants utilizing the power units manufactured by the Company to supply energy from geothermal fields and other alternative energy sources. Transfer prices between the operating segments were determined on current market values or cost plus markup of the seller's business segment.

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

	Electricity	Products	Consolidated
	(dollars in thousands)		
Year Ended December 31, 2006			
Net revenues from external customers	$ 195,483	$ 73,454	$ 268,937
Intersegment revenues	—	45,520	45,520
Depreciation and amortization expense	42,787	665	43,452
Operating income	50,314	11,614	61,928
Segment assets at year end*	1,104,326	55,776	1,160,102
Expenditures for long-lived assets	185,983	1,825	187,808
*Including unconsolidated investments	37,207	—	—
Year Ended December 31, 2005			
Net revenues from external customers	$ 177,369	$ 60,623	$ 237,992

Intersegment revenues	—	52,679	52,679
Depreciation and amortization expense	39,557	629	40,186
Operating income	56,831	7,078	63,909
Segment assets at year end*	864,968	49,512	914,480
Expenditures for long-lived assets	112,990	3,759	116,749
*Including unconsolidated investments	47,235	—	—
Year Ended December 31, 2004			
Net revenues from external customers	$ 158,831	$ 60,399	$ 219,230
Intersegment revenues	—	13,045	13,045
Depreciation and amortization expense	34,806	665	35,471
Operating income	55,895	6,549	62,444
Segment assets at year end*	812,816	37,272	850,088
Expenditures for long-lived assets	213,255	817	214,072
*Including unconsolidated investments	48,818	—	—

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

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Revenues:			
Total segment revenues	$ 268,937	$ 237,992	$ 219,230
Intersegment revenues	45,520	52,679	13,045
Elimination of intersegment revenues	(45,520)	(52,679)	(13,045)
Total consolidated revenues	$ 268,937	$ 237,992	$ 219,230
Operating income:			
Operating income	$ 61,928	$ 63,909	$ 62,444
Interest expense, net	(24,401)	(51,009)	(41,469)
Non-operating income (expense) and other, net	(10)	73	(34)
Total consolidated income before income taxes, minority interest, and equity in income of investees	$ 37,517	$ 12,973	$ 20,941

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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,		
	2006	2005	2004
	(dollars in thousands)		
Revenues from external customers attributable to:[1]			
North America	$ 191,819	$ 170,102	$ 137,124
Pacific Rim	7,952	10,646	50,362
Latin America	23,353	13,741	13,548
Africa	10,636	10,553	10,142
Far East	6,174	1,127	4,569
Europe	29,003	31,823	3,485
Consolidated total	$ 268,937	$ 237,992	$ 219,230

[1]Revenues as reported in the geographic area in which they originate.

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Long-lived assets (primarily power plants and related assets) located in:			
North America	$ 697,928	$ 590,365	$ 509,037
Latin America	105,332	38,682	26,938
Africa	49,570	51,311	53,423
Far East	—	—	571
Europe	6,220	5,060	1,837
Consolidated total	$ 859,050	$ 685,418	$ 591,806

The following table presents revenues from major customers:

	Year Ended December 31,					
	2006		2005		2004	
	Revenues (dollars in thousands)	%	Revenues (dollars in thousands)	%	Revenues (dollars in thousands)	%
Revenues from major customers:						
Customer A[1]	$ 80,665	30	$ 85,856	36	$ 90,808	41
Customer B[2]	—	—	5,281	2	31,058	14
Customer C[1]	34,320	13	33,583	14	28,298	13
Customer D[1]	40,517	15	36,207	15	15,470	7

[1]Revenues reported in Electricity Segment.

[2]Revenues reported in Products Segment.

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NOTE 16 — TRANSACTIONS WITH RELATED ENTITIES

Transactions between the Company and the related entities during the years presented below and balances as of the dates presented below, other than those disclosed elsewhere in these financial statements, approximated:

	Year Ended December 31,		
	2006	2005	2004
	(dollars in thousands)		
Transactions			
Revenues from an affiliate of the Parent	$ 3,503	$ 7,959	$ —
Property rental fee expense paid to Parent	$ 628	$ 627	$ 627
Interest expense on note payable to Parent	$ 8,367	$ 10,635	$ 9,723
Guarantee fees to Parent	$ 29	$ 204	$ 548
Corporate financial, administrative and executive services provided to Parent	$ 123	$ 120	$ 120
License fees to and services rendered by companies controlled by a shareholder of the Parent	$ 122	$ 162	$ —

	December 31,	
	2006	2005
	(dollars in thousands)	
Balances		
Due from Orzunil	$ —	$ 153
Due from subsidiary of Parent	$ 120	$ 167
Due from affiliate of Parent	$ 566	$ —

The Company has an agreement with the Parent whereby, for a fee, the Parent maintains certain standby letters of credit on behalf of the Company. During the years ended December 31, 2006, 2005 and 2004, the fees under the agreement totaled approximately $29,000, $204,000 and $548,000, respectively.

The current liability due to (from) Parent at December 31, 2006 and 2005 of ($1,459.000) and $356,000, respectively, represents the net obligation resulting from ongoing operations and transactions with the Parent and is payable from available cash flow. Interest is computed on balances greater than 60 days at LIBOR plus 1%, however not less than the change in the Israeli Consumer Price Index plus 4%, compounded quarterly, and is accrued and paid to the Parent annually.

Notes payable to Parent

In 2003, the Company entered into a loan agreement with the Parent, which was further amended on September 20, 2004 (‘‘Parent Loan Agreement’’) pursuant to which the Company may borrow from the Parent up to $150 million in one or more advances. Interest accrues on the unpaid principal of the loan amount at a rate per annum of the Parent’s average effective interest plus 0.3% (7.5% during 2004 and 2003). The principal and interest on the Parent Loan Agreement are payable in varying amounts through the loan due date of June 2010. The outstanding balance of such loan at December 31, 2006 and 2005 was $89,488,000 (including current portion of $31,647,000) and $121,140,000

(including current portion of $31,647,000), respectively. As further discussed in Note 1, on June 29, 2004, $20.0 million outstanding under the Parent Loan Agreement was converted to 1,160,714 shares of $0.001 par value common stock of the Company.

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In 2003, the Company entered into a NIS 240.0 million non-interest bearing note agreement with the Parent. Principal is payable upon demand at any time after November 30, 2007, but no later than December 30, 2009. The loan is subordinated to all other liabilities of the Company. In accordance with the terms of such note, the Company will not be required to repay any amount in excess of $50,665,000 (using the exchange rate existing on the date of such note). As of December 31, 2006 and 2005, the ceiling of $50,665,000 is effective. Since the note is payable upon demand at any time after November 2007 it is presented in the balance sheet as of December 31, 2006 in