



**ANNUAL INFORMATION FORM**

FOR THE YEAR ENDED JUNE 30, 2011

SEPTEMBER 27, 2011

## GENERAL MATTERS

In this Annual Information Form, unless otherwise noted or the context otherwise indicates, “Alterra”, the “Company”, “we”, “us” and “our” refers to Alterra Power Corp. and its direct and indirect subsidiaries.

### FORWARD-LOOKING INFORMATION

This Annual Information Form contains certain “forward-looking information” which may include, but is not limited to: statements with respect to future events or future performance; the capacity and electricity generation expectations of projects; management’s expectations regarding our growth; results of operations; business prospects and opportunities; expansion programs at the Reykjanes power plant and at our Soda Lake Operation; programs to upgrade and develop the Company’s inferred and indicated geothermal resources; qualification of expenditures at the Soda Lake Operation for U.S. Federal Treasury Grants; permitting for the Company’s expansion, development and exploration programs; negotiation of a power purchase agreement (“PPA”) related to an expansion of the Reykjanes power plant; estimates of recoverable geothermal energy “resources” or power generation capacities; estimates or predictions of gas content, porosity, permeability, fractures, reservoir temperature, reservoir pressure, steam cap temperature, well-head pressure and scaling; data collection, expansion, upgrade, development, reinjection, rework or inhibition plans for any of the Company’s properties; determining the feasibility of building the Upper Toba and Dokie Expansion projects; and permitting and regulatory requirements related to any such plans. Such forward-looking information reflects management’s current beliefs and is based on information currently available to management. Often, but not always, forward-looking statements can be identified by the use of words such as “anticipate”, “believe”, “forecast”, “plan”, “expect”, “is expected”, “budget”, “estimates”, “goals”, “intend”, “targets”, “aims”, “appears”, “likely”, “typically”, “potential”, “probable”, “continue”, “strategy”, “proposed”, or “project” or variations (including negative variations) of such words and phrases or may be identified by statements to the effect that certain actions “may”, “could”, “should”, “would” or “shall” be taken, occur or be achieved.

A number of known and unknown risks, uncertainties and other factors, may cause our actual results or performance to materially differ from any future results or performance expressed or implied by the forward-looking information. Such factors include, but are not limited to: failure to discover and establish economically recoverable and sustainable geothermal resources through our exploration and development programs; geothermal exploration and development programs are highly speculative, are characterized by significant inherent risk and costs, and may not be successful; hydrological and wind studies may not confirm that water flows are sufficient to generate enough electricity to support our planned hydro expansion or development programs; wind studies may not confirm that wind resources are sufficient to generate enough electricity to support our planned wind expansion or development programs; we have a limited history operating hydroelectric and wind power plants; our financial performance depends on our successful operation of power plants, which is subject to various operational risks; our renewable power resources may decline over time and may not remain adequate to support the operation of our power plants; imprecise estimation of renewable power resources or power generation capacities; imprecise estimation of resources and reserves of geothermal energy; variations in project parameters and production rates; geological or meteorological occurrences beyond our control may compromise our operations and their capacity to generate power; inability to obtain the financing we need to pursue our growth strategy; it is very costly to place power plants into commercial production; non-contracted power prices are subject to dramatic and unpredictable fluctuations; industry competition may impede our ability to access suitable renewable power resources; we may be unable to enter into PPAs on terms favourable to us, or at all; the cancellation or expiry of government initiatives to support renewable energy generation may adversely affect our business; impact of significant capital cost increases; unexpected or challenging geological conditions; changes to regulatory requirements, both regionally and internationally, governing development, geothermal resources, production, exports, taxes, labour

standards, occupational health, waste disposal, toxic substances, land use, environmental protection, project safety and other matters; failure to obtain or maintain necessary licenses, permits and approvals from government authorities; the success of our business relies on attracting and retaining key personnel; the risk of human error; our officers and directors may have conflicts of interests arising out of their relationships with other companies; we may face adverse claims to our title; developments regarding Aboriginal, First Nations and Indigenous peoples; fluctuations in foreign currency exchange and interest rates may affect our financial results; we may not be able to secure financing to construct new projects which are otherwise deemed feasible; we may not be able to successfully integrate businesses or projects that we acquire in the future; our insurance policies may be insufficient to cover losses; the governments of the countries in which the Company undertakes its activities may take action which results in fines or other penalties levied against the Company; aluminum price risk; undisclosed liabilities associated with the Company's acquisition of HS Orka hf ("**HS Orka**"); an adverse ruling in the Company's arbitration proceedings with Norðural Helgufvirk sf ("**Norðural**"); the results of operations of the companies in which we hold a significant interest; risks associated with inter-regional transmission grids; host country economic, social and political conditions can negatively affect our operations; economic, social and political risks arising from potential inability of end-users to support our properties; the fluctuation of our common share price could result in investors losing a significant part of their investment; we have no dividend payment policy; an issuance of additional equity securities may negatively impact the trading price of our common shares; the risk of volatility in global financial conditions, as well as significant decline in general economic conditions; and other exploration, development and operating risks. There may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. These factors are not intended to represent a complete list of the risk factors that could affect us. Additional risk factors are discussed in the section entitled "Risk Factors" in this Annual Information Form. These factors should be considered carefully and investors should not place undue reliance on forward-looking information.

The forward-looking information contained in this Annual Information Form is based upon what management believes to be reasonable assumptions, including, but not limited to: the effects of any increase in power production from our operations; the success and timely completion of planned exploration, development and expansion programs; our ability to comply with local, state, provincial and federal regulations dealing with operational standards and environmental protection measures; our ability to negotiate and obtain PPAs on favourable terms; our ability to obtain necessary regulatory approvals, permits and licences in a timely manner; the availability of materials, components or supplies; our ability to solicit competitive bids for drilling operations, construction or other relevant third party services and obtain access to critical resources; the growth rate in net electricity consumption; support and demand for renewable power generation; government initiatives to support the development of renewable power generation; the accuracy of volumetric reserve estimation methodology and probabilistic analysis used to estimate the quantity of potentially recoverable energy; the accuracy of the analysis used to estimate renewable resources and reserves; environmental, administrative or regulatory barriers to the exploration and development of resources on our properties; geological, geophysical, geochemical and other conditions at our properties; the reliability of technical data, including extrapolated temperature gradient, geophysical and geochemical surveys and geothermometer calculations; capital expenditure estimates; availability of capital to fund exploration, development and expansion programs; our competitive position; and general economic conditions. Forward-looking information is also based upon the assumption that none of the identified risk factors that could cause actual results to differ materially from the forward-looking information will occur.

There can be no assurance that the forward-looking information included in this Annual Information Form will prove to be accurate, as actual results and future events could differ materially from those anticipated in such information. Accordingly, investors should not place undue reliance on forward-looking information. Forward-looking information is made as of the date of this Annual

Information Form and, other than as required by applicable securities laws, we assume no obligation to update or revise such forward-looking information to reflect new events or circumstances.

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## INTRODUCTION

Unless otherwise indicated, the information contained herein is as at June 30, 2011.

### Reporting Currency

Unless otherwise indicated, all references to “\$” or “dollars” or in this Annual Information Form are to United States dollars. References to “Cdn.\$” are to Canadian dollars. References to “ISK” are to Icelandic Krona.

### Accounting Policies

All financial information in this Annual Information Form is prepared in accordance with Canadian generally accepted accounting principles.

### Scientific and Technical Information

The disclosure in this Annual Information Form of scientific nature or technical information for each of the Iceland properties, the Soda Lake Operation, the McCoy, Desert Queen and Thermo Hot Springs properties and Mariposa project, which consists of the Laguna del Maule and Pellado concessions (the “**Mariposa Project**”), is based on the following technical reports, respectively. These reports have been filed on the system for electronic document analysis and retrieval (“**SEDAR**”) and are available for viewing and downloading at [www.sedar.com](http://www.sedar.com).

- Geothermal Resources and Properties of HS Orka, Reykjanes Peninsula, Iceland: Independent Technical Report dated January 29, 2010 prepared by Mannvit hf (the “**HS Orka Report**”).
- Independent Technical Report: Geothermal Resources and Reserves at Soda Lake Project, Churchill County, Nevada USA dated April, 2010 prepared by GeothermEx, Inc. (“**GeothermEx**”) (the “**Soda Lake Report**”).
- Independent Technical Report Resource Evaluation of the McCoy Geothermal Project, Churchill and Landers Counties, Nevada dated April 29, 2009 prepared by Dr. J. Douglas Walker (Ph.D.) (the “**McCoy Report**”).
- Independent Technical Report Resource Evaluation of the Desert Queen Geothermal Project, Churchill County, Nevada dated May 12, 2009 prepared by Dr. J. Douglas Walker (Ph.D.) (the “**Desert Queen Report**”).
- Independent Technical Report Resource Evaluation of the Thermo Hot Springs Geothermal Project, Beaver County, Utah dated May 15, 2009 prepared by Dr. J. Douglas Walker (Ph.D.) (the “**Thermo Hot Springs Report**”).
- Mariposa Geothermal Resource, Laguna del Maule and Pellado Concessions, Chile dated July 17, 2010 prepared by Philip James White of Sinclair Knight Merz Limited (“**SKM**”) (the “**Mariposa Report**”).

With the exception of the Mariposa Report, the other reports were prepared during fiscal year 2009-10. These reports form the basis for the subsequent work carried out on, and the disposition of, the properties (where applicable). Each of the authors of the foregoing technical reports is independent of the Company. Geothermal properties and operations differ from mining or oil and gas properties and operations and Canadian securities regulators have not prescribed a form of technical report for geothermal properties, such as ours. Accordingly, the foregoing technical reports have not been prepared in accordance with National Instrument 43-101 – *Standards of Disclosure for Mineral Projects* (“**NI 43-101**”) or National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (“**NI 51-101**”). Furthermore, the authors of these technical reports are not qualified persons for the purposes of NI 43-101 or qualified reserves evaluators or auditors for the purposes of NI 51-101, however they are qualified persons under the Australian Code and the Canadian Code (as defined below). The HS Orka Report has been prepared in accordance with the standards set by the Australian Geothermal Reporting Code (the “**Australian Code**”). On January 18, 2010, the Canadian Geothermal Energy Association announced the release of the Canadian Geothermal Code for Public Reporting (the “**Canadian Code**”). The Mariposa Report and the Soda Lake Report comply with the Canadian Code. The Australian and Canadian Codes are considered as the geothermal standard for several countries in the world. All of the other technical reports have been prepared in accordance with accepted practices within the geothermal industry. The technical reports are available for review on the Internet on SEDAR at [www.sedar.com](http://www.sedar.com).

For an explanation of the technical terms used in this Annual Information Form, please see “Glossary of Terms” beginning on page G-1 of this Annual Information Form.

This Annual Information Form contains information from public sources on properties adjacent to our geothermal projects. The accuracy and completeness of this data are not guaranteed. The information presented in this Annual Information Form regarding adjacent properties is not necessarily indicative of the geothermal resources on our properties.

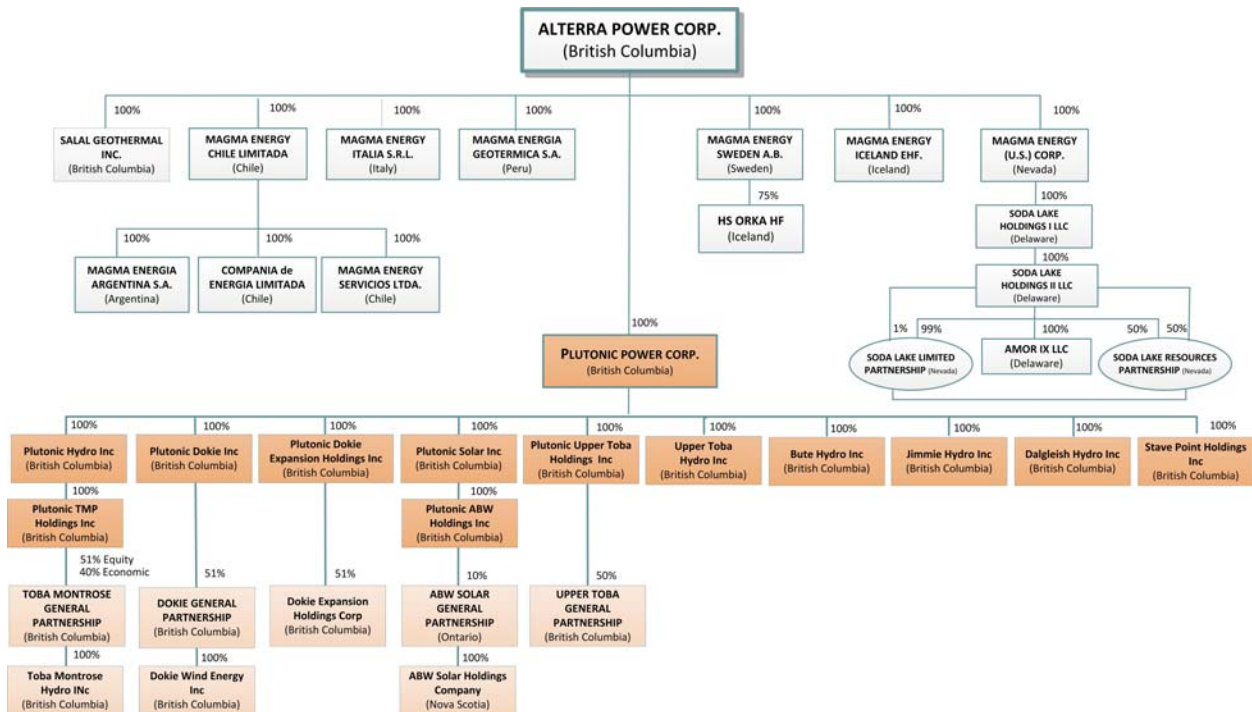
## CORPORATE STRUCTURE

### Name, Address and Incorporation

Alterra was incorporated as Magma Energy Corp. under the *Business Corporations Act* (British Columbia) on January 22, 2008. The Company’s name was changed from “Magma Energy Corp.” to “Alterra Power Corp.” on May 13, 2011. Our head office and registered and records office is located at Suite 600, 888 Dunsmuir Street, Vancouver, British Columbia, Canada, V6C 3K4. We also have offices in Reno, Nevada; Santiago, Chile; Reyknesbaer, Iceland; Powell River, British Columbia and Lima, Peru.

### Intercorporate Relationships

The following diagram illustrates the organizational structure of Alterra, including all its material subsidiaries, as at September 15, 2011.



## GENERAL DEVELOPMENT OF THE BUSINESS

The general development of our business since incorporation has focused on the acquisition of the Soda Lake Operation and our interest in HS Orka, the expansion into other types of renewable energy generation by our acquisition of Plutonic Power Corporation (“**Plutonic**”), the acquisition of our portfolio of advanced and early-stage properties and projects, the recruitment of our management team and the raising of equity capital.

We have also conducted an extensive review of historic exploration databases for a number of prospective geothermal exploration properties, including all of our advanced and early-stage exploration properties, and in this fiscal year continued exploration programs on our Soda Lake Operation, Desert Queen property, and our Mariposa Project.

During 2008, we:

- (i) Completed the acquisition of the Tuzgle-Tocomar and Coranzuli properties in Argentina and the Carrán and Laguna del Maule properties in Chile.
- (ii) Acquired leases in Nevada comprising the McCoy, Panther Canyon, Beowawe, Columbus Marsh and Quartz Mountain properties, and a portion of the Desert Queen property, at an auction conducted by the U.S. Bureau of Land Management (“**BLM**”).
- (iii) Formed Energia Geotermica S.A. to hold properties acquired in Peru.
- (iv) Acquired the Thermo Hot Springs property in Utah from a private leaseholder.
- (v) Acquired the Soda Lake Operation from Constellation Energy Group, Inc. and Harbert Management Corporation.
- (vi) Raised Cdn.\$10,000,000 in equity capital.

During 2009, we:

- (i) Acquired additional leases at the Desert Queen property from various private landowners.
- (ii) Entered into an agreement to acquire additional federal leases near the Soda Lake Operation from Sierra Geothermal Power Inc. and Western Geothermal Partners LLC.
- (iii) Acquired additional leases at the Desert Queen property from the Gabrych Family Trust.
- (iv) Incorporated Magma Energy Servicios Limitada in Chile.
- (v) Acquired 17 additional BLM leases in Nevada.
- (vi) Allowed the Carrán property in Chile to lapse.
- (vii) Acquired 8.62% of the shares of HS Orka from Geysir Green Energy ehf (“**Geysir Green**”).

- (viii) Acquired 32.32% of the shares of HS Orka from Reykjavík Energy and two other HS Orka shareholders for an aggregate 40.94% interest.
- (ix) Raised Cdn.\$160,889,133 in equity capital.
- (x) Completed our initial public offering and commenced trading on the Toronto Stock Exchange (“**TSX**”).

During 2010, we:

- (i) Were awarded the Pellado property by the Government of Chile. Pellado adjoins the Laguna del Maule Property, which properties together comprise the Mariposa Project.
- (ii) Were awarded an exploitation permit on the Laguna del Maule property in Chile, which allows for a geothermal operation of up to 50 megawatts (“**MW**”) to be developed within the permit area.
- (iii) Acquired two additional leases in Nevada from the BLM, one at the Desert Queen property and one in the area of the Granite Springs Property.
- (iv) Entered into a credit agreement (the “**2010 Credit Agreement**”) with Ross Beaty, the Company’s Chairman and Chief Executive Officer, pursuant to which the Company was able to borrow up to Cdn.\$20,000,000.
- (v) Were awarded two new concessions in Chile, Tres Puntos and Los Cristales.
- (vi) Increased our interest in HS Orka to 98.53%. Alterra filed a Form 51-102F4 Business Acquisition report on SEDAR with respect to its acquisition of HS Orka, a copy of which is available at [www.sedar.com](http://www.sedar.com).
- (vii) Raised Cdn.\$45,174,783 in equity capital

During 2011, we:

- (i) Acquired all of the outstanding shares of Plutonic, a TSX-listed renewable energy development company. The consideration payable by Alterra was 2.38 common shares of Alterra and Cdn.\$0.0001 in cash for each Plutonic common share, resulting in 149,657,200 Alterra common shares (net of dissent shares) being issued and \$6,288.14 being paid to Plutonic’s shareholders. It was concurrent with the closing of the acquisition of Plutonic that Magma Energy Corp. changed its name to “Alterra Power Corp.”. Plutonic’s common shares were delisted from trading on the Toronto Stock Exchange as of the close of business on May 17, 2011. Alterra filed a Form 51-102F4 Business Acquisition report on SEDAR with respect to its acquisition of Plutonic, a copy of which is available at [www.sedar.com](http://www.sedar.com).
- (ii) Sold a 25% interest in HS Orka to Jardvarmi slhf (“**Jardvarmi**”), a company owned by a group of Icelandic pension funds. The selling price of 8.06 billion ISK (approximately US\$70.1 million)<sup>(1)</sup> was approximately equal to Alterra’s original cost of acquisition. Jardvarmi also holds an option until February 10, 2012 to purchase new shares from HS Orka’s treasury that, if exercised, would increase its stake in HS Orka to 33.4% at a cost of 4.7 billion ISK (approximately US\$40.7 million)<sup>(1)</sup>.

- (iii) Purchased a 1.47% interest in HS Orka for 475.1 million ISK (approximately US\$4.2 million)<sup>(1)</sup> from four Icelandic municipalities. As a result of this acquisition and our sale to Jardvarmi, we now hold a 75% interest in HS Orka.
- (iv) Were awarded two geothermal exploration concessions in Italy in a competitive bidding process, PR Mensano and PR Roccastrada.
- (v) Were awarded two geothermal exploration concessions in Peru known as Crucero and Loriscota.
- (vi) Were awarded the “Pasto” geothermal concession in Peru which is contiguous with the Crucero and Loriscota properties.
- (vii) Agreed to sell the Beowawe and Baltazor early stage exploration properties in Nevada to Ormat Nevada Inc., and the Dixie Valley early stage exploration property in Nevada to TerraGen Power, LLC.
- (viii) Started the process to relinquish the Tuzgle-Tocomar and Coranzuli early stage exploration properties in Argentina.

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**Note:**

- (1) United States dollar conversion is based upon the exchange rates quoted by the Bank of Canada as of the date of the acquisition.

## **DESCRIPTION OF THE BUSINESS**

### **General**

Alterra Power Corp. is a leading global renewable power company, formed in 2011 through the merger of Magma Energy Corp. and Plutonic Power Corporation. We operate six power plants totaling 571 MW of capacity, including two geothermal facilities in Iceland, a geothermal plant in Nevada, British Columbia's largest run of river hydro facilities and the province's largest wind farm. Our 315 MW share of production capacity generates 1,518 GWh of clean power annually. The Company also has an extensive portfolio of exploration and development projects.

Prior to its acquisition of Plutonic, the Company was primarily a geothermal power company and was actively engaged in operating, developing, exploring and acquiring geothermal energy projects. The Company owns two geothermal power generation plants (the Svartsengi and Reykjanes Plants) and three geothermal exploration properties (the Eldvörp, Krýsuvík and Trölladyngja properties) in Iceland through its 75% interest in HS Orka. In addition, we currently own one geothermal power generation plant in Nevada (the Soda Lake Operation), a number of advanced-stage geothermal exploration properties (the McCoy and Desert Queen properties in Nevada, the Thermo Hot Springs property in Utah and the Mariposa Project in Chile) and a number of early-stage geothermal exploration properties located in Nevada, Peru, Chile and Italy.

Alterra's acquisition of Plutonic expanded its operations into other sources of renewable power, primarily run-of-river hydro and wind. In addition to our geothermal projects, we now own an interest in the Toba Montrose Facility and Dokie Wind Farm, both of which are located in British Columbia. We also own a number of water license applications for hydro power generation in British Columbia and an interest in the Dokie Expansion wind power generation site.

Each of these projects is described below.

Our head office is located in Vancouver, British Columbia, Canada. We also have offices in Reno, Nevada; Santiago, Chile; Reykjanesbær, Iceland; Powell River, British Columbia and Lima, Peru. In total and including HS Orka, we have 150 officers and employees.

### Overview of our Operations and Properties

The following provides a brief overview of our geothermal operations and properties.

<b>Property and Location</b>	<b>Property Type</b>	<b>Area (Ha)</b>	<b>Potential Megawatt Capacity<sup>(1)</sup> (MW)</b>	<b>Reserves/ Resources (MW)</b>	<b>Status</b>
<b>Iceland</b>					
Svartsengi	Production	175	n/a	75 / 0 <sup>(2)</sup>	Currently producing 75 MW electrical and 150 MW thermal <sup>(4)</sup>
Reykjanes	Production	340	n/a	100 / 80-100	Currently producing 100 MW electrical, with expansion of additional 80 MW electrical planned <sup>(4)</sup>
Eldvörp	Advanced Exploration	1,007	n/a	0 / 50	Under Development
Krýsuvík	Advanced Exploration	29,500	n/a	0 / 500	Under Development
Trölladyngja	Advanced Exploration	3,161	n/a	<sup>(3)</sup>	Under Development
<b>Total.....</b>		<b>34,183</b>	<b>n/a</b>	<b>175 / 780-800</b>	
<b>United States</b>					
Soda Lake <i>Nevada</i>	Production	2,071	n/a	16 / 28.5 <sup>(5)</sup>	Currently producing at 9 MW; possible expansion program to 16 MW
McCoy <i>Nevada</i>	Advanced Exploration	4,876	80	n/a	Environmental analysis work being carried out; exploratory drilling planned
Desert Queen <i>Nevada</i>	Advanced Exploration	4,408	36	n/a	Environmental analysis work being carried out
Thermo Hot Springs <i>Utah</i>	Advanced Exploration	706	20	n/a	No work planned for 2011/2012

<b>Property and Location</b>	<b>Property Type</b>	<b>Area (Ha)</b>	<b>Potential Megawatt Capacity<sup>(1)</sup> (MW)</b>	<b>Reserves/ Resources (MW)</b>	<b>Status</b>
Granite Springs, Soda Lake East, Upsal Hogback Nevada	Early-Stage Exploration	11,017	n/a	n/a	Under development – exploratory drilling and other exploration activities being carried out
<b>Total.....</b>		<b>23,087</b>	<b>136</b>	<b>16 / 28.5</b>	

### South America and Europe

Mariposa Chile	Advanced Exploration	104,000	n/a	0 / 320 <sup>(6)</sup>	Surface exploration underway, Magnetotelluric (“MT”) Survey completed, 3 slim holes drilled; prep for next drilling sites underway
Tres Puntos, Los Cristales Chile	Early-Stage Exploration	158,000	n/a	n/a	Surface mapping and geochemical survey
Crucero, Loriscota, Pasto Peru	Early-Stage Exploration	57,400	n/a	n/a	Preliminary exploration work continuing
Pinchollo, Huaynaputina, Ticsani, Ccollo, Casiri, San Pedro-Aychollo Peru	Early-Stage Exploration	6,950	n/a	n/a	Preliminary exploration work continuing
Mensano, Roccastrada Italy	Early-Stage Exploration	48,455	n/a	n/a	Detailed exploration program planned for 2012
<b>Total.....</b>		<b>374,805</b>	<b>n/a</b>	<b>0 / 320<sup>(6)</sup></b>	

#### Notes:

- (1) Geothermal resources and probabilistic estimates of MW capacity have a great amount of uncertainty as to their existence and as to whether they can be accessed in an economically viable manner. It cannot be assumed that all of, or any part of, a geothermal resource will be commercially extracted or that estimates of MW capacity will be achieved. Alterra plans to report according to the Canadian Geothermal Reporting Code, so that investors have a basis upon which to evaluate the statement made in terms of resource estimates.
- (2) The Reserves and Resources estimates for the Iceland properties are reported in accordance with the Australian Geothermal Reporting Code.
- (3) The Trölladyngja resource estimate is included within the Krýsuvík resource estimate.
- (4) Of which the Company’s share is 75%.

- (5) Assuming 12% recovery factor, 8% conversion efficiency and a 30-year project life. The Reserves and Resources estimates for the Soda Lake Operation are reported in accordance with the Canadian Code. Reserves and Resources estimates for geothermal properties are not prepared in accordance with NI 43-101.
- (6) The Reserves and Resources estimates for the Mariposa Project are reported in accordance with the Canadian Geothermal Reporting Code.

The following provides a brief overview of our non-geothermal operations and properties.

Property and Location	Property Type	Potential Megawatt Capacity (MW)	Status
<b>British Columbia – Hydro</b>			
East Toba River <sup>(1)</sup>	Production	145	Currently producing at 145 MW <sup>(5)</sup>
Montrose Creek <sup>(1)</sup>	Production	90	Currently producing at 90 MW <sup>(5)</sup>
Jimmie Creek <sup>(2)</sup>	Advanced Development	66	Construction cost estimating underway
Upper Toba River <sup>(2)</sup>	Advanced Development	58	Construction cost estimating underway
Bute Project <sup>(3)</sup>	Early-Stage Development	> 1,000	Hydrological studies being undertaken
Green Power Corridor <sup>(4)</sup>	Early-Stage Development	> 700	Hydrological data collection on some sites
		> 2,059	

Property and Location	Property Type	Potential Megawatt Capacity (MW)	Status
<b>British Columbia – Wind</b>			
Dokie Wind Farm	Production	144	Currently producing at 144 MW <sup>(6)</sup>
Dokie Wind Expansion	Early-Stage Development	> 150	Wind resource data being evaluated
		> 294	

Notes:

- (1) Together comprise the Toba Montrose Facility.
- (2) Together comprise the Upper Toba Project.
- (3) Comprised of a number of run-of-river hydro sites within a radius of approximately 50 km of the head of Bute Inlet.
- (4) A number of hydro sites on the southwestern coast of British Columbia.

- (5) Of which the Company's share is 40%.
- (6) Of which the Company's share is 51%.

## Geothermal Operations

We currently have two distinct business segments under our geothermal operations: the production and sale of geothermal power and the exploration and development of geothermal properties. All revenue and production was generated by our Iceland properties and our Soda Lake Operation in Nevada. The Company's portion of the revenue for the years ended June 30, 2009, June 30, 2010 and June 30, 2011 was as follows:

Year Ended	Energy Sales	Portfolio Energy Credit Sales	Total Revenue
June 30, 2009	\$3,963,167	\$521,963	\$4,485,130
June 30, 2010	\$5,055,751	nil	\$5,055,751
June 30, 2011	\$62,410,150	\$431,000	\$62,841,150

We will continue to investigate, evaluate and, where appropriate, acquire additional exploration and development geothermal properties.

### *Developments related to our acquisition of HS Orka*

In December, 2010, Alterra's wholly-owned subsidiary, Magma Energy Sweden A.B. ("**Magma Sweden**"), completed its acquisition of HS Orka by acquiring Geysir Green's remaining interest in HS Orka, bringing Alterra's interest to 98.53%. On June 1, 2011, Magma Sweden sold a 25% interest in HS Orka to Jardvarmi for ISK 8.06 billion (approximately \$70.1 million). On June 9, 2011, Magma Sweden purchased a 1.47% interest in HS Orka from four Icelandic municipalities for ISK 475.1 million (approximately \$4.2 million). The Company now holds 75% of the outstanding shares of HS Orka with the remaining 25% owned by the Icelandic pension funds' company Jardvarmi. Jardvarmi also holds an option exercisable until February 10, 2012 to purchase additional shares from HS Orka's treasury that, if exercised, would increase its ownership interest in HS Orka by 8.4% to 33.4%, for a cost of 4.7 billion ISK (approximately \$40.7 million). HS Orka accounts for the vast majority of Alterra's current production of geothermal power and, accordingly, the performance of HS Orka has a significant impact on our financial results.

HS Orka produces 175 MW of power from two operating plants located in the Reykjanes peninsula of Iceland. Both operations are connected to the Icelandic transmission grid with a 132 kiloVolt ("**kV**") transmission line. HS Orka has four PPAs: one with Landsvirkjun that terminates at the end of 2019, two with Norðural, an operator of aluminum smelters in Iceland, that terminate in October, 2011 and June, 2026, respectively, and one signed in February 2011 committing 30 MW of capacity to Iceland Silica Corporation ehf. commencing May 2013. A majority of the electricity demand in Iceland comes from the aluminum industry and in 2010, 73% of Iceland's total electricity consumption went to aluminum smelters, with 6% being consumed by other heavy industries.

### *Economic Dependence*

As at June 30, 2011, approximately 46% of HS Orka's current revenue is derived from power prices linked to aluminum market prices, however this is expected to be reduced to approximately 38% by October 2011. None the less, HS Orka's financial results, and in turn Alterra's financial results, are partially dependent on aluminum prices. Furthermore, HS Orka sells approximately 50% of its power to

Norðural and the balance to the retail market. As a result, much of HS Orka's revenue is dependent on one customer.

The Soda Lake Operation sells all of its current electricity output to NV Energy Company ("NV Energy") under two 30-year PPAs that terminate in 2018 and 2020, respectively.

### *Competitive Conditions*

The renewable power industry is intensely competitive. The Company competes with many companies possessing similar or greater financial and technical resources for the acquisition of early-stage development properties and for access to the capital required to develop those properties. In addition to competition for development properties and activities, the Company competes for capital to develop its operating assets.

The Company's competitive position is maintained by its access to capital and its focused, experienced management team.

### *Environmental Protection*

The Company's operations are subject to environmental regulation in the various jurisdictions in which it operates. To the best of management's knowledge, the Company's activities were, and continue to be, in compliance in all material respects with such environmental regulations applicable to its operations, development and exploration activities. The Company accepts its corporate responsibility to practice environmental protection and provide a safe and healthy workplace for its employees, and commits to comply with all relevant industry standards, environmental legislation and regulations in the countries where it carries on business.

### *Iceland*

The following is a summary description of the Company's Iceland properties. In January 2010 a report on the Iceland properties (the "**HS Orka Report**") was prepared on behalf of Alterra by Mannvit hf, and that report is incorporated by reference in this Annual Information Form. See "Introduction - Scientific and Technical Information". The full text of the HS Orka Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com), and contains a more detailed description of the Iceland properties.

As a result of Alterra's acquisition of a 75% interest in HS Orka, Alterra has obtained an indirect 75% interest in all of HS Orka's geothermal resources and properties. HS Orka's geothermal power plants (Svartsengi and Reykjanes) and its exploration properties (Eldvörp, Krýsuvík and Trölladyngja) are all located on the Reykjanes peninsula, southwest of Reykjavík, the capital of Iceland.

#### Svartsengi

The Svartsengi property is part of the Svartsengi geothermal field, which is located in the municipality of Grindavík approximately 45 kilometres southwest of Reykjavík. HS Orka has leased the Svartsengi property from the Reykjanesbær municipality for 65 years.

The Svartsengi plant is a combined geothermal heat and power plant that currently provides 75 MW of electricity and 150 MW of thermal district heat. The first power plant system was built in 1976 and has been upgraded in several stages since that time. The power plant has ten turbine/generator units of various sizes ranging from 1.2 MW to 30 MW. The Svartsengi power plant is connected to the Icelandic electrical transmission grid with a 132 kV transmission line.

The Svartsengi geothermal field is one of three high-temperature geothermal fields located in the very active volcanic rift zone on the western part of the Reykjanes peninsula. The geothermal field is liquid dominated with temperature in the range of 235 to 240°C, with natural steam zone found in the eastern part of the geothermal field. The produced fluid is approximately two-thirds seawater and one-third freshwater in composition.

To date, 23 wells have been drilled in the field. Seven wells produce from the liquid dominated part of the reservoir, while six wells produce dry steam from the steam cap. Two reinjection wells have also been drilled in the field. The average depth of the wells in use in the Svartsengi field is approximately 1,050 metres.

The Company has investigated whether the current 75 MW electrical production capacity of the Svartsengi plant can be maintained by the geothermal resource with current production and reinjection rates being maintained for the next 30 years.

The Svartsengi geothermal resource has been under investigation and exploration for approximately 40 years, resulting in a comprehensive understanding of the reservoir and its response to long term mass extraction. A detailed numerical model of the geothermal reservoir exists, which simulates the production and monitoring history with a high degree of confidence, resulting in reliable forecasts of the reservoir response to long term utilization.

Company modeling shows a reservoir pressure decline from 2010 to 2040 of approximately 25 bar. This forecasts a well-head pressure drop from 14 bar in 2009 to approximately ten bar in 2040, which is within the standard operational parameters of the Svartsengi power plant and sufficient to maintain current plant output.

As defined and in accordance with the Australian Code, with fluid temperature of approximately 240°C the Svartsengi geothermal field is classified as a proven reserve containing recoverable thermal energy of 75 MW electrical for 30 years, relative to the operational parameters of the Svartsengi geothermal power plant.

### Reykjanes

The Reykjanes property is part of the Reykjanes geothermal field, which is located at the southwest tip of the Reykjanes peninsula, approximately 20 kilometres south of Reykjanesbær. The Reykjanes plant is a steam driven power plant with a capacity of 100 MW. It was built in 2006 and has two steam turbine generator units. The Reykjanes geothermal power plant is connected to the Icelandic electrical transmission grid by a 132 kV transmission line.

The Reykjanes geothermal field is a liquid dominated high-temperature geothermal system with sea water as the reservoir fluid. The highest temperature in the system has been measured at approximately 320°C, but the dominate reservoir temperature is approximately 295°C. A total of 30 wells have been drilled in the Reykjanes geothermal field, of which 18 have been drilled for the 100 MW plant already in operation, one has been drilled as a research well and one has been drilled for the re-injection of fluid.

Since commencement of operation of the plant in 2006 a steam cap has developed at depths of approximately 800 to 1,200 metres, which has resulted in higher fluid enthalpy and reduced mass extraction from the field. The reduced extraction, and most likely increased recharge to the geothermal reservoir, has resulted in a reduced rate of pressure drawdown. Consequently, two shallow production wells have been drilled in the field with the objective of producing from the steam cap. The Company is currently planning a 50 MW electrical expansion of the Reykjanes plant for 2013 and it is anticipated that

this expansion will be supplied in two parts, with two-thirds coming from the steam zone and one-third from deeper parts of the reservoir. Accordingly, the planned expansion is highly dependent on the expansion and health of the steam cap. The Company anticipates a total of nine to twelve wells will be needed for the expansion, five of which will be for production, re-injection and for standby.

It is clear that utilization of the steam zone will result eventually in lower temperatures of the steam cap and an impact on well-head pressure and the output of wells producing from the steam cap. The reduced temperature of the steam zone and declined well output will probably call for the drilling of make-up wells to replace the declining well output, but the confirmed need for these wells is currently not known.

A further 30 MW expansion by way of secondary flash turbine is also being planned for 2014, however the Company does not anticipate that any additional drilling will be required for this expansion as the power source will be low pressure steam generated from current operations.

The Company has been granted an operating permit for the 80 MW expansion of the Reykjanes plant by Orkustofnun, the National Energy Authority of Iceland.

The forecasts of the reservoir pressure drawdown and well-head pressure indicate that the Reykjanes geothermal reservoir is capable of supplying high-pressure steam to the current 100 MW electrical Reykjanes power plant plus both the 50 MW and 30 MW electrical expansions through 2040. However, it can be assumed that replacement wells may be needed sometime in the future to make up for declining well output rates.

As defined and in accordance with the Australian Code the Reykjanes geothermal system contains a proven reserve with recoverable thermal energy of 100 MW electrical for 30 years and an indicated resource with electrical generation capacity of 80-100 MW electrical for 30 years, relative to the current operational parameters of the Reykjanes geothermal power plant and with the planned secondary flash unit successfully installed.

The Company's expansion plans of adding another 50 MW electrical turbine and a 30 MW electrical secondary turbine to the existing operation is within the production capability of the current resource, with the assurance that continued reservoir monitoring, reinjection and active numerical modeling is maintained in order to ensure the continued sustainability of the reservoir for 30 years, and beyond.

### Eldvörp

The Eldvörp property is part of the Eldvörp geothermal field, which is located approximately five kilometres west southwest from the Svartsengi plant. The Company has an exclusive exploration and exploitation license in the Eldvörp geothermal field until 2057.

The Eldvörp geothermal field is located within the same Reykjanes fissure swarm as both the Reykjanes and Svartsengi geothermal field. The field has been studied to some extent and has been included in several surveys as part of investigations of the Svartsengi geothermal field since the 1980's. Results show that the Eldvörp and Svartsengi geothermal fields are two parts of the same geothermal resource.

The Eldvörp geothermal field is a liquid dominated high-temperature geothermal system with a steam zone from surface down to approximately 800 metres depth. The reservoir temperature in Eldvörp is approximately 270°C. The composition of the reservoir fluid in Eldvörp is approximately two-thirds seawater and one-third fresh water.

The Company has plans to develop a 50 MW electrical geothermal power plant on the property by 2015. Because the Eldvörp and Svartsengi geothermal fields are connected and both are part of the same geothermal reservoir, a power plant in Eldvörp could be envisioned as an expansion to the existing power plant in Svartsengi. It is therefore important to investigate the Svartsengi reservoir pressure response to any future mass extraction at Eldvörp, as studies indicate mass extraction needed to supply the Eldvörp power plant will result in increased reservoir pressure drawdown at Svartsengi and the well-head pressure decline of production wells.

Based on the results and interpretations predicted by the Company's modelling and in accordance with the Australian Code, the Eldvörp geothermal resource is classified as an indicated resource containing sufficient recoverable thermal energy of 50 MW electrical for 30 years, assuming 50% reinjection and energy utilization parameters similar to the parameters defined by the Svartsengi geothermal power plant.

### Krýsuvík

The Krýsuvík geothermal area, which includes the Sandfell and Trölladyngja geothermal fields, covers approximately 29,500 hectares and is owned primarily by the Hafnarfjörður municipality and a number of private land owners. The Company has an exclusive exploration license over the complete Krýsuvík geothermal area until 2016.

The Krýsuvík geothermal area belongs to the Krýsuvík volcanic centre and associated fissure swarm and is considered to cover approximately 80 square kilometres. The Krýsuvík geothermal area is divided into three sub-geothermal fields named Krýsuvík, Trölladyngja and Sandfell. The area has been known for a long time to be geothermally active and geothermal investigations date back to 1756.

Systematic exploration started in the 1940's with the drilling of 20 shallow wells at depths of approximately 200 metres. In 1960, three deeper exploration wells were drilled with the deepest one reaching a depth of 1,275 metres. Systematic exploration efforts were continued in the 1980s, including wells drilled to depths of approximately 800 to 900 metres, resulting in detailed research reports. From 1997 to 2001, resistivity campaigns were conducted to outline the extent of the geothermal resource.

The geological and exploration results obtained in the Krýsuvík geothermal area provide good evidence that the geothermal resource exists in a form, quality and quantity sufficient for eventual economic extraction. However, temperature data from geothermal wells and other geothermal information available is limited, compared to the indicated extent of the resource, to accurately predict the temperature distribution of the Krýsuvík geothermal resource. As a result, the Company plans to drill three deep (>2,000 metres) exploration wells as the next step in the development of the Krýsuvík field.

The geothermal resource at Krýsuvík area, including the Sandfell and Trölladyngja sub-geothermal resources, is classified according to the Australian Code as an inferred geothermal resource with approximately 105,000 petajoules of thermal energy in place, relative to 5°C. The recoverable and converted energy is equivalent to approximately 500 MW electrical for 30 years, by assuming a 20% thermal energy recovery and 7% efficiency factor.

### Trölladyngja

The Trölladyngja geothermal field is located in the Krýsuvík geothermal area. The Company has an exploration license in the Trölladyngja geothermal field, as part of the Krýsuvík exclusive exploration license, until 2016.

Several research and exploration studies have been conducted in the Trölladyngja field since the 1960s as part of the studies for the Krýsuvík geothermal area.

The geothermal information obtained from the two deep exploration wells in Trölladyngja show that a geothermal resource exists in the field. However, the temperature information available is limited and insufficient to confidently estimate the temperature distribution of the Trölladyngja geothermal resource. Further exploration drilling, research and development is required.

Similar to the greater Krýsuvík geothermal resource, the Trölladyngja geothermal resource is also classified as an inferred geothermal resource according to the Australian Code with approximately 32,000 petajoules thermal energy in place, relative to 5°C. The recoverable and converted energy is equivalent to approximately 150 MW electrical for 30 years, by assuming a 20% thermal energy recovery and 7% efficiency factor. The Trölladyngja geothermal resource is included in the Krýsuvík geothermal resource.

#### *Geothermal Resource and Geothermal Reserve Estimates*

In summary, the resource and reserve estimates of the Company's Iceland properties are as follows:

Property	Reserves (MW Electrical)		Resources (MW Electrical)	
	Proven	Probable	Indicated	Inferred
Svartsengi	75			
Reykjanes	100		80-100	
Eldvörp			50	
Krýsuvík				500
Trölladyngja				150 <sup>(1)</sup>
<b>Total.....</b>	<b>175<sup>(2)</sup></b>		<b>130-150<sup>(2)</sup></b>	<b>500<sup>(2)</sup></b>

**Note:**

- (1) The Trölladyngja resource estimate is included within the Krýsuvík resource estimate.
- (2) Of which the Company's share is 75%.

#### *United States*

##### *United States Geothermal Leases*

Typically, when we acquire an interest in a property with geothermal potential in the United States we do so by entering into a lease with the owner of the property. The lease grants us the right to explore and develop the geothermal resources on the property. In addition, the lease allows us to use as much of the surface of the property as required to accomplish these objectives.

Many of the leases presently held by us cover public lands owned by the U.S. Government and have been issued by the BLM. In some cases, the BLM leases were acquired by us through a competitive bidding process and we are the initial holder of the lease and the beneficiary of the full term of the lease. For example, the rights to the McCoy, portions of Desert Queen and Granite Springs properties were acquired

in this fashion. In other cases, we have taken an assignment of BLM leases from other leaseholders during the existing term of a BLM lease. Our Thermo Hot Springs property is an example of an assignment acquisition. In some cases, we have supplemented our holdings in certain areas by entering into leases with private landowners. In the case of a lease with a private landowner, we generally pay an annual rental payment for the right to explore and develop the geothermal resources on the property. If a geothermal plant is placed in service on the property, the lease generally requires the payment of royalties in place of the annual rental payment. In most cases, the annual rental payments are credited against any royalties payable to the owner.

The BLM leases we acquired at competitive lease sales in Nevada have a primary term of ten years, with the possibility of obtaining certain extensions of the lease term. If a geothermal plant is developed on the property, the leases convert to a royalty structure. Rental fees are payable annually to the U.S. Minerals Management Service (“MMS”) in the amount of \$2.00 per acre in year one, \$3.00 per acre in years two through ten, and \$5.00 per acre thereafter. These rental fees are payable even after the leases are in production status, however, rental fees are credited against royalties due. Once production commences, royalties are payable to MMS in the amount of 1.75% of gross proceeds on the sale of electricity for the first ten years, increasing to 3.5% of gross proceeds after the first ten years of production and for as long as the property produces power; provided, however, that a royalty of 10% of gross proceeds is payable on arms-length sales of electricity.

BLM leases grant the holder the exclusive right to explore for and develop the geothermal resources found beneath the lease, subject to the satisfactory completion of requisite administrative, operational, environmental, and cultural resource permitting requirements, and compliance with the *Geothermal Steam Act of 1970*, as amended, the regulations thereunder, the *National Environmental Policy Act*, as amended, and related environmental protection statutes governing endangered species, clean air, clean water, and cultural resource management.

#### *Soda Lake Operation*

In April 2010 a report on the Soda Lake Operation was prepared on behalf of Alterra by GeothermEx, and that report is incorporated by reference in this Annual Information Form. See “Introduction - Scientific and Technical Information”. The full text of the Soda Lake Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com) and contains a detailed description of the Soda Lake Operation. A summary description of the Soda Lake Operation follows.

The Soda Lake Operation is located in the southwest portion of Churchill County, Nevada, approximately 11 kilometres northwest of Fallon and 115 kilometres east of Reno. The Soda Lake Operation project area is defined by the Soda Lake Unit Agreement, which consists of 1,003.2 hectares of private land leases and 1,067.5 hectares of federal land leases for a total of 2,070.7 hectares.

Following its acquisition of the Soda Lake Operation in 2008 the Company designed a two phased expansion approach as follows:

- Phase 1 – a drilling/exploration and plant upgrade program to restore the generating capacity back to the original nameplate of 23.1 MW gross (16 MW net) by drilling new production wells and upgrading and refurbishing the existing power plant equipment.
- Phase 2 - conditional upon the successful completion of the Phase 1 drilling/exploration program and additional reservoir definition, a further expansion program to increase nameplate capacity to realize the ultimate reservoir potential. The minimum expansion target for Phase 2 is an additional capacity of 10 MW net.

Phase 1 was completed in 2010, and included the addition of two new production wells, one new steam/mixing well, plant refurbishments and the drilling of one new injection well. The Phase 1 work contributed 2 MW of net output to the Soda Lake Operation.

Phase 2 was commenced in 2010 with the completion of a 3D-3C seismic survey and a thermal gradient drilling program. This resulted in the issuance of a Department of Energy phase 1 draft report recommending the drilling of two deep slim step-out observation wells, which were commenced in summer 2011.

The Soda Lake Report concludes that the Soda Lake Reservoir contains a proved reserve of 14.2 MW net and an additional 28.5 MW net indicated resource.

Alterra has numerous federal lands under lease which are located in proximity to the Soda Lake Operation. Geothermal resource development may occur on these lands with appropriate permit approval, and the Soda Lake Operation may be expanded, with BLM approval, if or when the results of additional exploration and development indicate there is a geological basis for doing so.

The Soda Lake Operation sells all of its current electricity output to NV Energy under two 30-year PPAs that terminate in 2018 and 2020, respectively. Given the Company's plans to expand and increase the output of the Soda Lake Operation, management is of the opinion that a re-negotiation of the existing agreements and/or a new agreement for additional production will be required.

#### *McCoy Property*

In April 2009 a report on the McCoy property was prepared on behalf of Alterra by Dr. J. Douglas Walker (Ph.D.), and that report is incorporated by reference in this Annual Information Form. See "Introduction - Scientific and Technical Information". The full text of the McCoy Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com) and contains a detailed description of the McCoy property. A summary description of the McCoy property follows.

The McCoy property is located in Nevada and straddles the boundary between Churchill County on the west and Lander County on the east, approximately 50 kilometres northwest of Austin. There is no power transmission infrastructure in the immediate property area, but the site is 25 kilometres from a north-south 230 kV transmission line that has approximately 50 MW of capacity available. There is also an east-west 230 kV transmission line with excess capacity approximately 22 kilometres south of the project area.

The McCoy property consists of four BLM leases. The lands were acquired by the Company at a lease auction conducted by the BLM in August 2008 with additional acreage being added in 2009. The primary lease term for the property is ten years with the possibility of three additional five-year extensions. If a commercial well is drilled on the property, then the acreage can be converted to "held-by-production" status, which continues for as long as the property produces geothermal fluids.

During the year the Company carried out work on the environmental analysis required to obtain the permits necessary to develop the property, and it intends to continue with this work during 2011 and 2012.

### *Desert Queen Property*

In May 2009 a report on the Desert Queen property was prepared on behalf of Alterra by Dr. J. Douglas Walker (Ph.D.), and that report is incorporated by reference in this Annual Information Form. See “Introduction - Scientific and Technical Information”. The full text of the Desert Queen Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com) and contains a detailed description of the Desert Queen property. A summary description of the Desert Queen property follows.

The Desert Queen property is located within and adjacent to the Hot Springs Mountains in west-central Churchill County, Nevada. The site is approximately 38 kilometres northwest of Fallon and is near the Desert Peak and Brady Hot Springs geothermal facilities and our Soda Lake Operation, three of the twelve producing geothermal fields in Nevada.

The Desert Queen property consists of six BLM leases covering 2,838.7 hectares and two private fee land leases covering 1,569.3 hectares for a total of 4,408 hectares.

The private fee land leases provide for an exclusive five-year exploration period with the option to extend for an additional five years, and will convert to production status once a commercial well is drilled on the property for as long as the property produces geothermal fluids. The Company is obligated to pay a royalty to the fee landholders similar to those paid to the federal government under the BLM leases based on a percentage of the gross sale of electricity and the percentage contribution of geothermal fluids derived from a lessor’s property. Three previously owned private fee land leases have been relinquished, and negotiations with another private fee lease owner for additional acreage are in progress.

During the spring of 2011 botanical and raptor surveys were undertaken as part of the environmental analysis required to obtain the permits necessary to develop the property. The Company intends to continue with its environmental analysis in 2011 and 2012.

### *Thermo Hot Springs Property*

In May 2009 a report on the Thermo Hot Springs property was prepared on behalf of Alterra by Dr. J. Douglas Walker (Ph.D.), and that report is incorporated by reference in this Annual Information Form. See “Introduction - Scientific and Technical Information”. The full text of the Thermo Hot Springs Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com) and contains a full description of the Thermo Hot Springs property. A summary description of the Thermo Hot Springs property follows.

The Thermo Hot Springs property is located in Beaver County, Utah approximately 50 kilometres south-southwest of the Roosevelt Hot Springs. It consists of a single discontinuous 706 hectare BLM lease parcel, which was purchased from a private leaseholder in August 2008. This previous leaseholder retains an overriding royalty of 1.5% on gross proceeds derived from the sale of electricity generated from the lease. The primary ten year lease expires on October 1, 2012.

Based on the technical data presented in the Thermo Hot Springs Report and additional backup data, it is reasonable to conclude that there exists a substantial, but unquantified, geothermal resource beneath the Thermo Hot Springs property lease area. Temperature gradient and geophysical data are consistent with source fluid temperatures in the 150°C to 200°C range at depths of 2,000 to 2,500 metres. Temperatures in this range are commercially attractive for generating electricity using single or double flash technology. Geochemical as well as geological and geophysical indicators from the property are consistent with these findings. In addition, the presence of geologically active faults indicates abundant permeability and suggests that open fractures should be maintained. A program of geophysical, geological and

geochemical work would be the first step in developing the property, however the Company does not plan on undertaking any work on the property during 2011 and 2012.

#### *Early Stage Exploration Properties*

##### Granite Springs Property

The Granite Springs property is located in Pershing County, west-central Nevada. The property consists of five BLM leases with a total area of 5,937 hectares that were acquired at BLM auctions in August 2009 and May 2010. The effective dates of the leases are September 1, 2009 and June 1, 2010. It is anticipated that some additional geophysical exploration and deeper temperature gradient hole drilling will be done starting in 2012 or 2013.

The Granite Springs property is a large contiguous block of land that overlies a shallow thermal anomaly up to eight miles long in a north-south direction and up to four miles long in an east-west direction. This thermal anomaly was originally outlined with approximately 30 shallow temperature-gradient holes and lies in the central part of the broad Granite Springs Valley. One slim hole was drilled in 1983 to a depth of 547 metres and measured a maximum temperature of 90°C at the bottom of the hole. The temperature gradient at the bottom of the hole was close to zero so there is no way to predict what temperatures are likely to be at greater depths. There are no surficial thermal features associated with the shallow thermal anomaly but two water samples were recovered from shallow wells within the thermal anomaly, giving predicted quartz geothermometer temperatures of 108°C and 162°C and Na/K/Ca predicted temperatures of 124°C and 191°C. To the west of the thermal anomaly the active Shawave Fault Zone separates the Shawave Mountains from Granite Springs Valley and is a likely structural target. Perhaps some eastern strands of this fault zone or hidden faults further east of the mountains transmit hot water up to shallow depths in the western part of Granite Springs Valley. This thermal anomaly has only had one slim hole drilled into it, and the Company feels it is worthy of additional exploration. The Company anticipates conducting additional geophysical exploration and deeper temperature gradient hole drilling in 2012 or 2013.

##### Soda Lake East Property

The Soda Lake East property is located in Churchill County, west-central Nevada, approximately two miles east of the Soda Lake Operation. The property consists of one BLM lease with a total area of 1,526 hectares that was acquired at a BLM auction in August 2009. The effective date of the lease is September 1, 2009.

The Soda Lake East property is a greenfield prospect located between the operating Stillwater geothermal field and the Soda Lake Operation. To date the Company has not carried out any significant exploration in this area.

##### Upsal Hogback Property

The Upsal Hogback property is located in Churchill County, west-central Nevada, and essentially forms a ring around the northern part of the Soda Lake Operation. The prospect consists of two BLM leases with a total area of 3,554 hectares that were acquired at a BLM auction in August 2009. The effective date of the leases is September 1, 2009.

The Upsal Hogback property overlies the distal portions of the Soda Lake thermal anomaly. A portion of this property can be viewed as containing the northwest, north, and east margins or extensions of the Soda Lake resource while the more northerly part of the property most likely lies beyond the resource

boundary. Four sections of BLM land were relinquished in 2011 due to the lack of compelling geologic argument that further work should be completed on those lands. The drilling of a slim hole temperature gradient well up to 1,220 metres in depth is planned for Fall 2011 in the property, and will parallel a slim hole drilled on the property in October, 2010.

### *South America and Europe*

#### *Mariposa Project*

In July 2010 a report on the Mariposa Project was prepared on behalf of Alterra by Philip James White of SKM, and that report is incorporated by reference in this Annual Information Form. See “Introduction - Scientific and Technical Information”. The full text of the Mariposa Report is available for review on SEDAR at [www.sedar.com](http://www.sedar.com) and contains a detailed description of the Mariposa Project. A summary description of the Mariposa property follows.

The Mariposa Project is comprised of the adjacent Laguna del Maule and Pellado geothermal concessions, which are located approximately 300 kilometres south of Santiago and 120 kilometres southeast of Talca in the Maule Region of Chile. Alterra has been working on the Laguna del Maule geothermal concession since 2008. This exploration concession was purchased from the University of Chile and originally covered an area of 400 square kilometres. In July 2009, Alterra applied for four square kilometres of this area to be converted into an exploitation concession, and that was awarded by the Chilean government on May 5, 2010. Alterra applied for rights to the Pellado exploration concession, located to the west of Laguna del Maule concession, in early 2009, with the concession being granted in January 2010. The Pellado concession was awarded on January 11, 2010 and published on January 19, 2010. The concession has a two year term and an extension of the term was applied for in July 2011. The Laguna del Maule exploitation concession is for an unlimited term.

A geothermal system has been outlined that extends between the Laguna del Maule and Pellado concessions, which is now known as the Mariposa geothermal system.

Alterra has carried out geological mapping, chemical sampling and analysis of fumaroles, an MT resistivity survey over Laguna del Maule and part of the Pellado concession and the drilling of three slimholes. The first hole was completed to a depth of 659 metres and a maximum temperature of 202°C was measured just above the bottom of the well. The second hole was drilled to a depth of 897 metres and had a maximum measured temperature of 193°C, and flowed for several weeks in early 2011. The third hole was drilled to a depth of 883 metres and a temperature of 205°C was measured during injection testing. To provide for access to these drill sites, 24 kilometres of road and crew facilities were constructed. Plans are underway for continued drilling during 2011/2012.

#### *Early-Stage Exploration Properties*

##### Chile

###### Los Cristales Property

The Los Cristales property is a 68,000 hectare concession located immediately south of the Pellado concession. The Company was awarded the concession in November 2010 and received the official decree on January 20, 2011. The Company has completed preliminary exploration work on the property.

## Tres Puntas Property

The Tres Puntas property is a 90,000 hectare concession located in the Atacama Region, 800 km north of Santiago. The Company was awarded the concession in November 2010 and received the official decree on January 20, 2011. The Company has completed preliminary exploration work on the property.

## Peru

Instituto Geológico Minero Y Metalúrgico (“**INGEMMET**”), the geological survey department of the Peruvian Ministry of Energy and Mines (“**MEM**”), undertook a series of studies of thermal and mineral waters across Peru in the late 1990’s and early 2000’s. Over 500 springs have been characterized by water chemistry, geology and the potential source of thermal waters. Some work on reservoir temperatures has also been carried out.

There are three tectonic settings associated with thermal springs in Peru. These are deep, recent faulting associated with uplift (and extension) of the Andes, active volcanism in the southern Andes and basins filled with sediments. Of these three settings, the area of active volcanism has high potential for very high temperature geothermal resources. In this region of active volcanism in the Southern Andes there are many springs associated with young volcanism and areas of extensive alteration. Hot springs with surface temperatures reported as high as 89°C are found. Accordingly, most of our activity in Peru is focused in this region.

Recent years have seen a dramatic shift in Peru’s electricity generation sector. Traditionally, the country has met the majority of its electricity needs through hydroelectric installations. By the mid-1990s, the country realized that natural gas was a feasible alternative to hydroelectric projects, and greater emphasis was placed on the development of thermal generation facilities.

By 2006 hydroelectric production accounted for 69% of Peru’s total electricity production and gas-fired thermal electricity production accounted for the remaining 31%. The transmission capacity of the country was increased and by 2006 installed capacity for transmission lines had reached 84% of the country. Since then the government has continued to increase its distribution capacity.

Peru has allowed for private development and operation of power generation facilities since 1992. Currently, the private sector, including foreign companies, controls approximately 65% of the generating capacity and 72% of the distribution system in Peru, which is market-based.

Increased awareness of global climate change and the impact of gas-fired thermal electricity generation on the environment has more recently resulted in Peru promoting the generation of electricity through other non-traditional renewable energy generation processes, such as wind, solar and geothermal, including the provision of significant tax incentives. This has resulted in a favourable government, legal and regulatory framework for geothermal exploration (and ultimately power production) in Peru.

The Company has applied for 27 exploration concessions in Peru. The first three concessions have been awarded (Loriscota, Crucero and Pasto), while the others are in various stages of the award process. The Crucero and Loriscota concessions lie in southern Peru’s prospective region of volcanoes and geothermal systems, approximately 50 km northwest of the town of Candarave. The concessions cover 37,400 hectares of land on a seven km long area of silica sinter and hot springs that follow extensional faults believed related to a strike-slip pull-apart basin. In Crucero, in particular, there are hot springs that approach boiling in places, widespread opaline silica sinters, and favorable liquid geochemistry associated with extensional faults. A transmission line lies 45 km to the northwest. The Company is working with the local communities and landowners to obtain access in preparation for full scale exploration in 2012.

In July 2011, the Company was awarded the Pasto concession, which covers 20,000 hectares and is adjacent to the Crucero concession.

Due to over and under lapping land applications and protected areas, the remaining concessions may be awarded in whole or in part. While waiting for our geothermal lease concession applications to be processed by MEM, we have secured our land position in several concession areas through the acquisition of mineral claims over the relevant lands. The concession areas secured by mineral claims are the Casiri, Ccollo, Pinchollo, Huaynaputina, Ticsani and San Pedro-Aychullo areas. During the period of waiting for the award of the geothermal concessions the Company has undertaken limited field work, consisting primarily of surface mapping and geochemical sampling. The Company plans to continue limited field work in 2011, and also commence a vigorous program of community engagement in association with INGEMMET and other geothermal companies active in the region.

### Italy

In March 2011 Alterra acquired two geothermal concessions in Italy, Mensano and Roccastrada. The concessions are near the Lardarello geothermal area, which has been in production for nearly 100 years, and the Monte Amiata geothermal system. The Roccastrada concession is 27,190 hectares in size and is characterized by the presence of high heat flow and hot springs that are the expression of a hydrothermal system that may be similar to that found at Monte Amiata. The Mensano concession is 21,265 hectares in size and is characterized by high heat flow, hot springs, hydrothermal alteration area, recent travertine deposits and significant uplifting on a regional scale.

The Company will begin preliminary work on both areas in 2011. This will be followed by a detailed exploration program undertaken in both areas in 2012 to confirm the presence of high heat enthalpy resources. The work will include geological, geophysical and geochemical work suitable to define the best locations and targets for slimhole exploration drilling, which will likely commence in 2013.

### **Hydro and Wind Operations**

The Company has a number of hydro and wind electricity generation and development sites in British Columbia. The Company is also party to an agreement whereby it can acquire an interest in several solar farms in Ontario, once construction of the solar farms has been completed.

The Company's Toba Montrose Facility and Dokie Wind Farm are in production, and the Company's portion of revenue for the years ended June 30, 2009, June 30, 2010 and June 30, 2011 was as follows:

<b>Year Ended</b>	<b>Energy Sales</b>	<b>Portfolio Energy Credit Sales</b>	<b>Total Revenue</b>
June 30, 2009	Nil	n/a	Nil
June 30, 2010	Nil	n/a	Nil
June 30, 2011	\$7,991,897	n/a	\$7,991,897

### *The Electricity Market in British Columbia*

Demand for electricity in British Columbia has been steadily increasing, driven by population and economic growth. The Company has identified a number of long-term trends which it believes will increase the demand in British Columbia for clean power generated from environmentally friendly, low-impact sources such as the Company's projects. These include:

- The Government of British Columbia’s stated intention that BC Hydro will retain ownership of existing “heritage” assets, and that new generation supply will be provided by the private sector.
- The increasing global trend towards concern for the environment and environmental stewardship, which drives demand for sources of low-impact, renewable power.
- Increasing government mandated minimum targets for renewable energy in the overall supply mix.

To date, management has focused on the sale of electricity to the British Columbia market through the provincial utility, BC Hydro. BC Hydro is one of the largest electric utilities in Canada, owning and supplying the majority of power generating capacity in the province. The remaining capacity is provided by private utilities, large and small industrial self-generators and independent power producers (such as the Company).

In 2002 the Government of British Columbia announced its BC Energy Plan (the “**Plan**”), subsequently updating the Plan in February 2007. The Plan set out goals to ensure that British Columbia would have the reliable and domestically supplied electricity needed to meet ongoing, growing demand.

In 2010 the Government of British Columbia followed up the Plan with the *Clean Energy Act* (the “**CEA**”). The CEA puts into law the British Columbia government’s long standing commitment to clean energy and the reduction of greenhouse gases and establishes a long term vision for British Columbia to become a clean energy powerhouse. The CEA sets out a number of specific energy objectives that will guide the provincial government, BC Hydro and the British Columbia Utilities Commission (“**BCUC**”) in advancing this vision, focusing on three areas:

1. Ensuring Electricity Self-Sufficiency at Low Rates

The province’s legislated goal of electricity self-sufficiency by 2016 was strengthened with a new regulatory framework for long-term electricity planning, commitments to clean and renewable electricity generation, streamlined approval processes and new measures to promote electricity efficiency and conservation. The CEA also strengthened protection for the province’s ratepayers with new measures to promote competitive rates and to ensure that all of the benefits from BC Hydro’s heritage assets continue to flow to British Columbians. These objectives are to be accomplished through long-term planning; public investments and conservation; and new investments in clean, renewable power and energy security. The BCUC will continue to ensure appropriate rates are set in advancing government’s energy objectives and long-term resource plans.

2. Harnessing BC’s Clean Power Potential to Create Jobs in every Region

The CEA provides BC Hydro and renewable power producers with the tools necessary to establish British Columbia as a clean energy powerhouse that enables economic growth and job creation in every region. It enables BC Hydro to maximize the value of its energy resources for ratepayers and taxpayers. It provides a new model to secure long-term export power sales to other jurisdictions seeking clean power by partnering with renewable power producers without risk or cost to the province’s ratepayers. The CEA also consolidated British Columbia Transmission Corp. with BC Hydro and created a First Nations Clean Energy Business Fund to provide the opportunity for First Nations to create investment and jobs in renewable power production.

### 3. Strengthening Environmental Stewardship and Reducing Greenhouse Gases

The CEA enshrined in law measures the Province will take to reduce greenhouse gas emissions, help customers save money through conservation and protect the environment. The provincial *Environmental Assessment Act* process was strengthened to specifically provide for assessments of potential cumulative environmental effects. In addition, the development or proposal of energy projects in parks, protected areas and conservancies is prohibited by law.

For more information on the CEA go to [www.gov.bc.ca/cleanenergyact](http://www.gov.bc.ca/cleanenergyact).

In the Spring of 2011, the new provincial government of Premier Christy Clark announced a review of proposed BC Hydro rate increases with the intention of bringing forward recommendations and options for minimizing proposed rate increases. The review was conducted by three senior civil servants and looked at both operating and capital requirements for BC Hydro. While the CEA itself was not under review, the scope of the review was sufficiently broad that recommendations and options had the potential to effect changes in independent power procurement practices in the province.

#### *Competitive Environment*

At the present time the Company considers that the only feasible purchaser of electricity generated by the Company and other independent power producers in British Columbia is BC Hydro, pursuant to electricity purchase agreements (“EPAs”) which are awarded in calls for power. These calls for power are the electricity procurement process undertaken by BC Hydro, where from time to time it invites independent power producers to tender offers for EPAs for their projects to BC Hydro. The Company’s development properties in British Columbia are therefore substantially dependent on obtaining EPAs from BC Hydro for its projects, and the Company competes for EPAs with other independent power producers who are developing power projects using run-of-river and other technologies, including wind and biomass. These independent power producers range in size from large utilities to small independent power producers.

Each power production technology has benefits and drawbacks. In general, on an economic and environmental basis, run-of-river and wind technology is competitive with other forms of clean power generation.

#### *Run-of-River Hydroelectric Power*

All but one of the Company’s hydro sites in British Columbia are run-of-river hydroelectric generation sites. Run-of-river hydroelectric generation facilities differ from traditional hydroelectric facilities, which require the damming of a river or other water course and the consequent flooding of large areas of land to provide a reservoir of water to be used to drive the turbines to generate electricity. A run-of-river project only requires a minimal amount of retention of water in a stream or river, limiting it to the amount required to submerge the intake mouth of a conveyance pipe, or penstock. Through the construction of a weir a portion of the water flowing in the stream or river is diverted into a downward sloping penstock which delivers the water to drive turbines located at the bottom of the grade. The water is then returned to the river without altering the existing flow or water levels downstream.

It should be noted that because a run-of-river project does not have the ability to store water, the amount of electricity it can generate is dependent on water flow. The weather patterns in the areas where the Company’s projects are located generally result in increased water flows in the spring and summer months. This has the potential to enhance BC Hydro’s ability to better shape its supply of electricity to meet demand, as BC Hydro’s generation capacity is primarily from dam-created reservoirs. BC Hydro

would be able to utilize run-of-river produced electricity during high water months instead of drawing down its reservoirs, and thereby allowing its reservoirs to be replenished during low water months. This essentially allows BC Hydro's reservoirs to function as large batteries storing power that can be generated by BC Hydro on demand.

The environmental attributes of electricity generated by run-of-river hydroelectric facilities allow them to be classified as environmentally friendly clean power projects. These attributes include the following:

- Zero greenhouse gas emissions
- No pollution or wastes created
- Small environmental footprint
- Low visual impact
- Minimal impact on fish, vegetation, bird and wildlife habitat

### *Wind Power*

Wind power is used to generate electricity by positioning a set of blades similar to a propeller so that the force of the wind blowing over the blades causes them to spin, which in turn drives an attached generator. The generators are housed in nacelles which are traditionally mounted on top of towers located in windy areas, which automatically rotate and orient to the direction of the wind.

Wind energy has evolved from an emerging source of energy to become a significant resource in many countries.

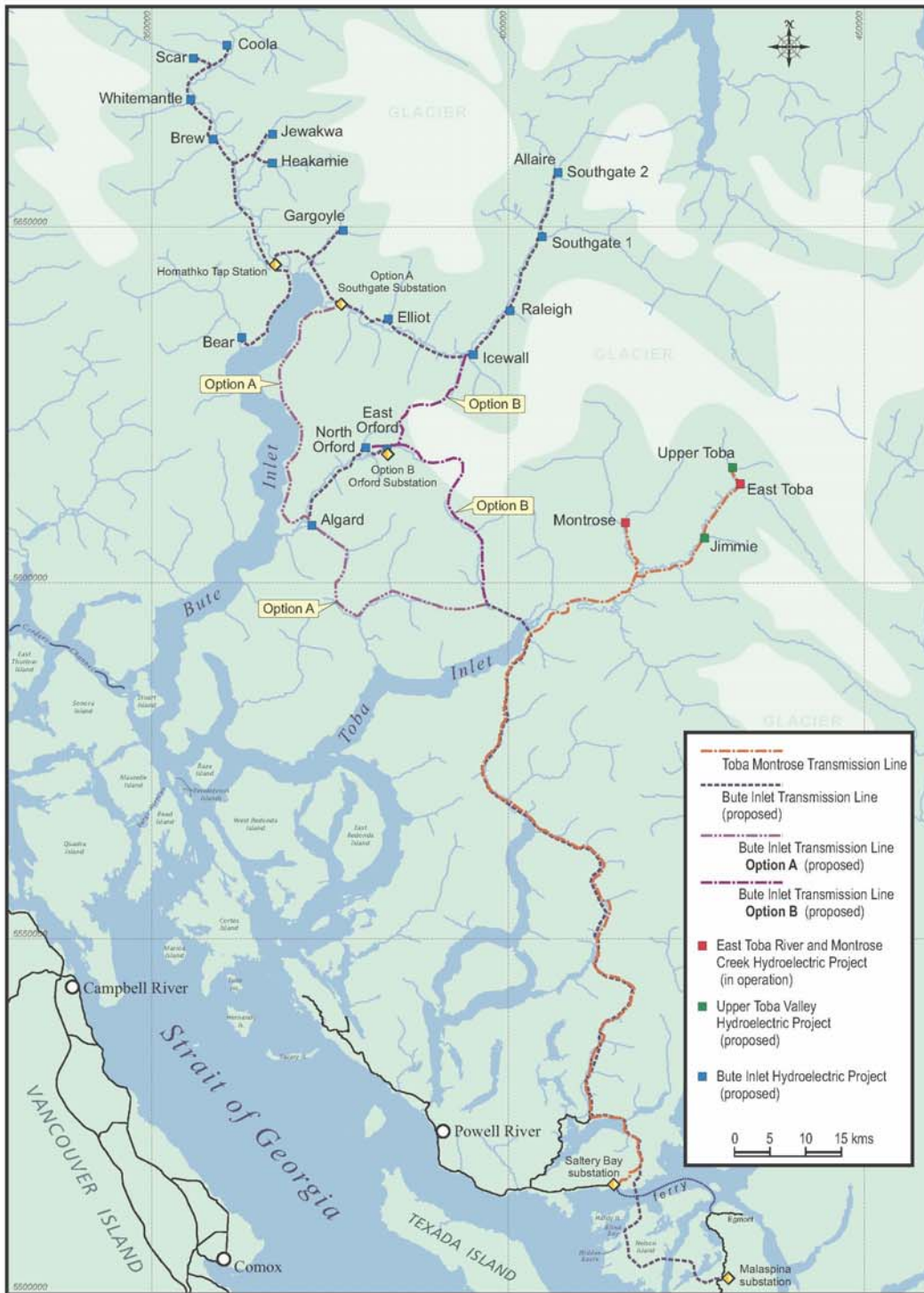
Global installed wind power capacity has grown continuously over the past 15 years. Europe dominates the global wind power industry, having approximately 61% of total installed wind power capacity. In Canada, government initiatives to foster the development of wind power were implemented somewhat later than in many other countries around the world. However, since 2001, the Canadian wind power market has been growing, driven largely by national production incentives and provincial renewable power targets.

The environmental attributes of electricity generated by wind power allows it to be classified as environmentally friendly clean power. These attributes include the following:

- Zero greenhouse gas emissions
- No pollution or wastes created
- Small environmental footprint
- Non-restrictive use of land
- Minimal impact on fish, vegetation, bird and wildlife habitat

### ***The Company's Hydro and Wind Projects in British Columbia***

The location of the Toba Montrose Facility and the sites comprising the Upper Toba Project and Bute Inlet Project are located on the following map.



## Toba Montrose Facility

The Toba Montrose Facility has been in commercial operation since May 2010 and is owned by Toba Montrose General Partnership (“**TMGP**”), of which the Company owns a 51% equity and 40% economic interest. The remaining interests in TMGP are owned by GE Energy Financial Services Holding Company, an affiliate of General Electric.

### Project Overview

The Toba Montrose Facility is comprised of two run-of-river power generation sites, one on the East Toba River and one on Montrose Creek. Both generation sites are located northeast of the head of Toba Inlet, approximately 100 km north-northeast of Powell River, BC. A new 230 kV transmission line to carry the generated electricity to SALTERY Bay for interconnection to the BC Hydro transmission grid was built as part of the Toba Montrose Facility.

The East Toba facility is a 145 MW run-of-river facility in the East Toba River drainage basin, located approximately 45 km northeast of Toba Inlet’s northernmost extent. This facility diverts water into a penstock intake on the East Toba River which drops in elevation to a surface powerhouse containing turbines in the lower reach of the river. The facility, with its intake located at an elevation of approximately 690 metres above sea level, drains an area of approximately 188 square kilometres. The facility is expected to generate a net 452 GWh of electricity per year.

The Montrose Creek facility is a 90 MW run-of-river facility in the Montrose Creek drainage basin, located approximately 29 km northeast of Toba Inlet’s northernmost extent. This facility diverts water into a penstock intake on Montrose Creek which drops in elevation to a surface powerhouse containing turbines in the lower reach of the creek. The facility, with its intake located at an elevation of approximately 512 metres above sea level, drains an area of approximately 99 square kilometres. The facility is expected to generate a net 275 GWh of electricity per year.

Access to the head of Toba Inlet is by boat, barge and aircraft. A combination of rehabilitated logging roads and new roads built by TMGP provide access from the head of Toba Inlet up the Toba River valley to the East Toba and Montrose Creek facilities.

The electricity generated from the Toba Montrose Facility is transmitted via a new 230 kV transmission line approximately 155 km in length which was built by TMGP and interconnects to the transmission grid at SALTERY Bay, on Jervis Inlet. The transmission line was routed to take advantage of existing logging roads in lower lying areas and to avoid private land, First Nations land reserves, sensitive areas, and parks. Generally, the line was built using wooden H-Poles, but steel towers were utilized for added strength in high elevation locations. The right-of-way is located on Crown Land and maintained at a width of 40 metres, with only low bush being allowed to grow in it.

### Status of the Toba Montrose Facility

On August 31, 2006 TMGP and BC Hydro entered into a 35 year EPA for the Toba Montrose Facility, pursuant to which electricity from the Toba Montrose Facility is purchased by BC Hydro.

The Toba Montrose Facility generation facilities are located within the traditional territory of Klahoose First Nation, and the transmission line that links the Toba Montrose Facility's generation facilities to the transmission grid crosses the traditional territories of Klahoose, Sliammon and Sechelt First Nations. The substation that interconnects the Toba Montrose Facility’s generation facilities to the transmission grid is

within the traditional territory of Sechelt First Nation. TMGP has entered into Impact Benefit Agreements with all three of these First Nations, which allow access through the First Nations' traditional territories and provides revenue sharing, employment and contracting opportunities for First Nations' members.

The Toba Montrose Facility qualifies for participation in the ecoEnergy Program, a Canadian federal government program to encourage construction of renewable and green projects. Qualified projects are entitled to receive from ecoEnergy an incentive of Cdn.\$10 per MWh for up to 10 years for eligible low-impact, renewable electricity projects built prior to March 31, 2011. On February 16, 2009 TMGP signed an agreement with the Government of Canada pursuant to which TMGP receives Cdn.\$10 per MWh, which commenced with commercial operation of the Toba Montrose Facility in August 2010.

### Upper Toba Project

The Upper Toba Project, which is not yet under construction, is comprised of two run-of-river power generation sites, one located on Jimmie Creek and one located on Upper Toba River. Both of the sites are located northeast of the head of Toba Inlet, in the vicinity of the Toba Montrose Facility.

The Jimmie Creek site envisages a 66 MW run-of-river facility in the Jimmie Creek drainage basin, located approximately 30 km northeast of Toba Inlet's northernmost extent. This facility would divert water into a penstock intake on Jimmie Creek which drops in elevation to a surface powerhouse containing turbines in the lower reach of the creek. The development would drain an area of approximately 93 square kilometres and generate an estimated net 167 GWh of electricity per year.

The Upper Toba River site envisages a 58 MW run-of-river facility in the Upper Toba River drainage basin, located approximately 45 km northeast of Toba Inlet's northernmost extent. This facility would divert water into a penstock intake on the Upper Toba River which drops in elevation to a surface powerhouse containing turbines in the lower reach of the river. The development would drain an area of approximately 78 square kilometres and generate an estimated net 149 GWh of electricity per year.

The two sites are both located in close proximity to the Toba Montrose Facility, and with the construction of a minimal amount of connector transmission lines, would be able to utilize the transmission line built for the Toba Montrose Facility to interconnect to the transmission grid. The roads and other infrastructure built to construct the Toba Montrose Facility could also be used to construct the Upper Toba Project, together with some additional mainline and other roads to access the new intake locations.

On March 31, 2009, the Company received an Environmental Assessment Certificate from the Environmental Assessment Office ("EAO") for the Upper Toba Project. In December 2009 the Canadian Environmental Assessment Agency completed its screening level review under the *Canadian Environmental Assessment Act*, allowing the Upper Toba Project to proceed.

On March 29, 2010 the Company's subsidiary, Plutonic Upper Toba Holdings Inc., and GE EFS Canada Investment Holding Company, an affiliate of General Electric, formed the Upper Toba General Partnership ("UTGP") and on April 28, 2010, UTGP and BC Hydro entered into a 40 year EPA for the Upper Toba Project.

During 2010 the Company carried out hydrological studies and engineering, cost estimating, environmental work and interconnection studies on the Upper Toba Project, at a cost of approximately \$1.0 million. During 2011 the Company's primary focus will be on engineering and cost estimating, with the objective of making a construction decision by the end of the year.

The Impact Benefit Agreements entered into with Sliammon and Sechelt First Nations for the Toba Montrose Facility are also applicable to the Upper Toba Project, so the Company will not need to enter into separate agreements with those two First Nations for the Upper Toba Project. The Impact Benefit Agreement entered into with Klahoose First Nation for the Toba Montrose Facility is applicable to some, but not all, aspects of the Upper Toba Project, and the Company will be required to negotiate an Impact Benefit Agreement with the Klahoose First Nation for certain aspects of the Upper Toba Project. Negotiations between the Company and Klahoose First Nation on an Impact Benefit Agreement for the Upper Toba Project are ongoing.

### Bute Inlet Project

The Bute Inlet Project, which is not yet under construction, consists of a number of run-of-river sites located within a radius of approximately 50 km of the head of Bute Inlet, which is located approximately 150 km north of Powell River, British Columbia. The Bute Inlet Project will require transmission facilities to be built to transmit the electricity generated. The currently planned configuration is a 500 kV line from Bute Inlet to the BC Hydro substation located at Malaspina, where it will interconnect with the transmission grid.

Significant logging and other industrial activity has occurred in the vicinity of Bute Inlet since the 1980s, resulting in the development of an extensive network of roads in the area. The Company should be able to utilize these roads for construction of some of the Bute Inlet Project facilities, however the rehabilitation of a number of existing and the construction of additional new roads will likely be required.

In May 2007, the Company submitted the Bute Inlet Project into the British Columbia Environmental Assessment Permitting Process, with the EAO consequently issuing a Section 10 order binding the project to review under the *Environmental Assessment Act*. The size of the Bute Inlet Project has also triggered the requirement for a more comprehensive review by the Canadian Environmental Assessment Agency (“CEAA”) under the *Canadian Environmental Assessment Act*, and in May 2009 the Federal Minister of the Environment determined that the environmental assessment of the Bute Inlet Project would be conducted under the extensive panel review process. In June 2010 the Company advised CEAA that it was extending the timeline for development of the Bute Inlet Project. The reasons for the extension were the project not having an EPA with BC Hydro, a reduction in the likelihood that the project would receive an EPA within a reasonable time period and with the possibility of a reconfiguration of the project due to additional field study results there is uncertainty on what the composition of the project may be moving forward. CEAA accordingly disbanded the panel in spring 2011.

All of the generation sites for the Bute Inlet Project are located in the traditional territory of the Homalco First Nation, and the transmission line will run across the traditional territories of the Homalco, Klahoose, Sliammon and Sechelt First Nations. During 2010 the Company entered into an Impact Benefit Agreement with Sechelt First Nation, and in July, 2011 it entered into an Impact Benefit Agreement with Homalco First Nation. The Impact Benefit Agreements with Sechelt and Homalco First Nations include terms regarding access through their traditional territories, payment of access and construction fees, revenue sharing, employment, training and contracting opportunities for First Nation members and provisions providing for management of future transmission access through their traditional territories. Discussions with the other two First Nations are ongoing.

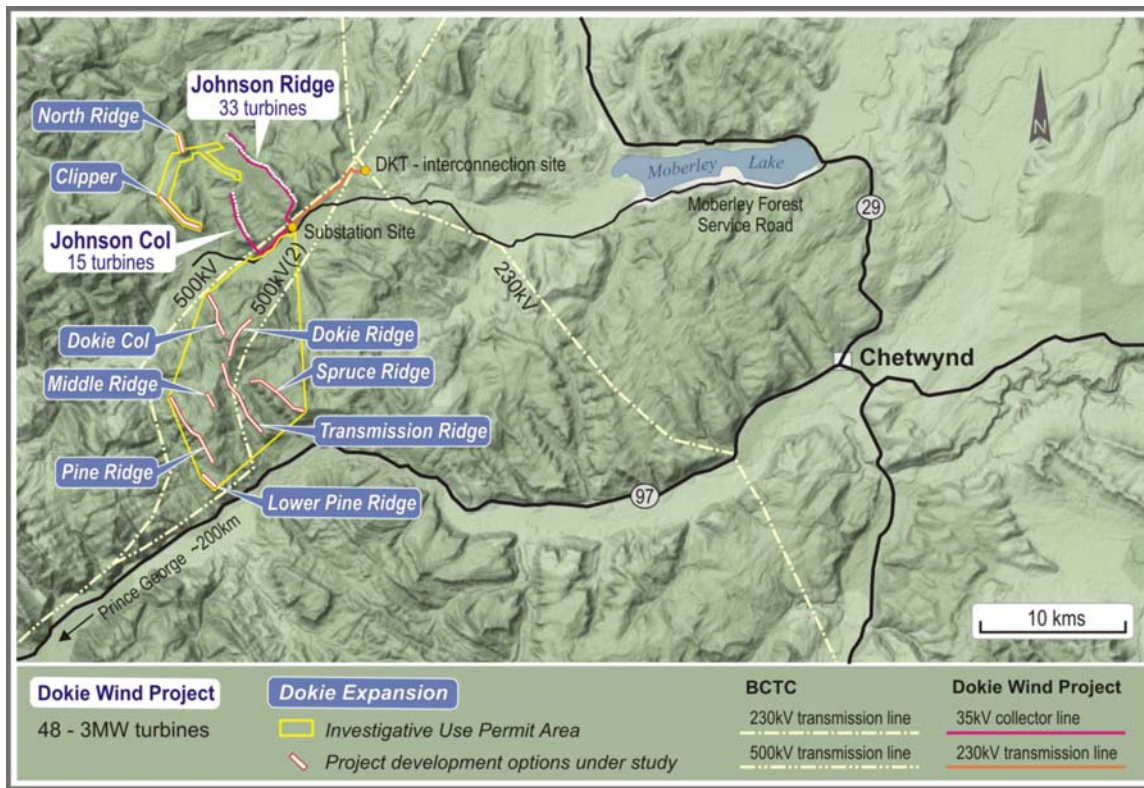
During 2010 the Company continued with hydrological studies and cost effective environmental baseline work on the Bute Inlet Project sites. Given the extended timeline for development of the Bute Inlet Project, the Company plans to focus primarily on hydrological studies during 2011.

## Dokie Wind Farm

The Dokie Wind Farm commenced commercial operation on February 16, 2011 and is owned by Dokie General Partnership (“**DGP**”), of which the Company owns 51% interest. The remaining interest in DGP is owned by GE Energy Financial Services Company, an affiliate of General Electric.

### Project Overview

The Dokie Wind Farm is a 144 MW capacity wind farm located approximately 40 km west of Chetwynd, in north-eastern British Columbia. The location of the Dokie Wind Farm and the sites comprising the nearby Dokie Expansion Project (see “Other Projects – Dokie Wind Expansion”) are located on the following map.



The Dokie Wind Farm consists of 48 wind turbine generators (“**WTGs**”) located on two ridges, with each WTG having a capacity of three MW. The first ridge, Johnson Col, has 15 WTGs installed in a line of approximately 3,500 metres and the second ridge, Johnson Ridge, has 33 WTGs installed in a line of approximately 7,500 metres. Each WTG is comprised of a tower 80 metres in height topped with a three MW Vestas V-90 turbine nacelle, which has a turbine blade sweep diameter of 90 metres. The Dokie Wind Farm will generate between 320 and 340 net GWh of electricity per year.

The Dokie Wind Farm includes approximately 17 km of 35 kV collector lines running from the WTGs to the project substation. At the substation power is stepped up to 230 kV and then carried approximately seven km by a 230 kV transmission line to an interconnection point with BC Hydro’s transmission grid.

## Status of the Dokie Wind Farm

DGP and BC Hydro have entered into a 25 year EPA for the Dokie Wind Farm, pursuant to which electricity from the Dokie Wind Farm is purchased by BC Hydro.

The Dokie Wind Farm is located within the traditional territories of the West Moberly, Saulteau and Halfway River First Nations and the McLeod Lake Indian Band. DGP has entered into Memoranda of Understanding with all of these First Nations, which agreements allow access through the First Nation's traditional territories and provides revenue sharing, employment and contracting opportunities for First Nation members.

The Dokie Wind Farm also qualifies for participation in the ecoEnergy Program, and on November 19, 2009 DGP signed an agreement with the Government of Canada pursuant to which DGP receives Cdn.\$10 per MWh for a period of 10 years, which commenced with commercial operation in February 2011.

## ABW Solar Project

The ABW Solar Project consists of three photovoltaic solar facilities to be built in southern Ontario by First Solar, Inc. ("**First Solar**"). The three facilities are being built near the towns of Amherstburg (10 MW), Belmont (20MW) and Walpole (20 MW). Completion of permitting for the project under Ontario's Renewable Energy Approval process is expected in the fall of 2011, with construction expected to begin by late-2011 and be completed by late-2012.

The ABW Solar Project is being developed by First Solar, an Arizona based company that designs, manufactures and sells solar power modules using a proprietary thin film semiconductor technology. Its business includes project development, engineering, procurement & construction, operating and maintenance services. First Solar will build the three photovoltaic solar facilities and then provide operation and maintenance services under a long-term contract.

On December 23, 2010 Plutonic ABW Holdings Inc., a wholly owned subsidiary of the Company, formed ABW Solar General Partnership ("**ABWGP**") with GE Energy Financial Services ABW Solar Company. On January 4, 2011, ABWGP agreed to acquire the ABW Solar Project from First Solar once it is complete in 2012. The Company is expected to make an equity contribution of approximately Cdn.\$6 million for a 10% interest in the project, and serve as the managing partner of the ABW Solar Project. Project debt will be arranged by First Solar on behalf of ABWGP and is expected to be in place to allow ABWGP to acquire the ABW Solar Project upon completion.

The ABW Solar Project will sell its power to the Ontario Power Authority under 20-year PPAs and will interconnect to Ontario's distribution grid at five points.

## Other Projects

### Green Power Corridor<sup>TM</sup> Projects

The Company has completed Stages 1 and 2 towards securing Water Licenses and Crown Land rights from British Columbia Ministry of Natural Resource Operation for the development of a number of run-of-river and one pumped storage sites on the southwestern coast of BC, an area which the Company has named the "Green Power Corridor"<sup>TM</sup>, or "GPC".

The Company's activities on these projects has been limited to collecting hydrological data and preliminary engineering work on some of the sites, and it expects to maintain this activity level during 2011 and 2012.

#### Dokie Wind Expansion

Located on a number of ridges to the south and west of the Dokie Wind Farm is the Dokie Expansion Project. The Dokie Expansion Project is owned 51% by the Company and 49% by Dokie Wind Holdings Company, an affiliate of General Electric. During 2010 the Company evaluated the wind resource data for the project in order to determine the potential capacity of the project, and plans to continue with this evaluation in 2011.

### DIVIDENDS

Alterra has not declared or paid any dividends since incorporation. Our anticipated capital requirements are such that we intend to follow a policy of retaining earnings in order to finance further business development at the present time, however we intend to consider a change to this policy in the future when circumstances allow. The declaration of dividends on our common shares is within the discretion of our Board of Directors and will depend upon their assessment of our earnings, capital requirements, operating and financial condition and other factors it considers to be appropriate. There are no restrictions on our ability to pay dividends.

### DESCRIPTION OF CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of common shares without nominal or par value. The holders of common shares shall be entitled to receive dividends, as and when declared by the Board of Directors out of monies properly applicable to the payment of dividends, in such amount and in such form as the Board of Directors may from time to time determine and all dividends which the Board of Directors may declare on the common shares shall be declared and paid in equal amounts per share on all common shares at the time outstanding. In the event of the dissolution, liquidation or winding up of the Company, whether voluntary or involuntary, or any other distribution of assets of the Company among its shareholders for the purpose of winding up its affairs, the holders of the common shares shall be entitled to receive the remaining property and assets of the Company. The holders of common shares shall be entitled to receive notice of and attend all meetings of the shareholders of the Company and shall have one vote for each common share held at all meetings of the shareholders of the Company.

### MARKET FOR SECURITIES

The common shares of the Company trade on the TSX under the trading symbol "AXY". The following table sets forth the price ranges and volume of trading of the common shares on the TSX for each month during the fiscal year ended June 30, 2011:

Month Ended	Volume	High	Low	Close
July, 2010	10,356,600	1.33	1.00	1.20
August, 2010	6,525,000	1.29	1.05	1.14
September, 2010	2,855,000	1.24	1.11	1.16
October, 2010	4,793,200	1.29	1.15	1.22
November, 2010	5,115,800	1.53	1.19	1.43
December, 2010	3,129,600	1.50	1.32	1.47

<u>Month Ended</u>	<u>Volume</u>	<u>High</u>	<u>Low</u>	<u>Close</u>
January, 2011	5,042,200	1.49	1.19	1.25
February, 2011	4,901,300	1.35	1.16	1.22
March, 2011	12,309,700	1.27	1.05	1.15
April, 2011	7,548,200	1.18	0.93	0.94
May, 2011	6,364,855	0.96	0.83	0.89
June, 2011	6,592,798	0.89	0.65	0.71

### ESCROWED SECURITIES

The following is a summary of the common shares held in escrow or that are subject to contractual restriction on transfer as at June 30, 2011, and the percentage of Alterra's outstanding common shares represented by such escrowed or restricted securities.

<u>Name or Category of Shareholder</u>	<u>Designation of Class</u>	<u>Number of common shares held in escrow or that are subject to contractual restrictions on transfer</u>	<u>Percentage of Outstanding common shares</u>
ROSS J. BEATY	Common shares	100,000,001	21.5%
INITIAL INVESTORS	Common shares	2,625,000	0.6%

Pursuant to a lock-up agreement entered into among Alterra, Raymond James Ltd., Cormark Securities Inc. and Ross J. Beaty, Mr. Beaty is prohibited from selling 100,000,001 common shares currently held by him for a period of four years from July 7, 2009. However, Mr. Beaty may assign all or a portion of such common shares to a non-profit foundation "The Sitka Foundation", provided The Sitka Foundation in turn agrees to be bound by such prohibition.

Pursuant to lock-up agreements entered into among Alterra, Raymond James Ltd., Cormark Securities Inc. and 15 of our initial investors (the "**Initial Investors**"), an aggregate of 10,500,000 common shares purchased by the Initial Investors in April 2008 at a price of Cdn.\$0.001 per common share (the "**Initially Offered Shares**") are subject to contractual restrictions on transfer. Subject to any additional statutory or stock exchange imposed hold periods, the Initial Investors are prohibited from selling in excess of one-quarter of the Initially Offered Shares held by them in each of the six month periods beginning six, 12, 18 and 24 months after July 7, 2009, without the prior written consent of Raymond James Ltd. and Cormark Securities Inc. An aggregate of 2,625,000 shares remain subject to these restrictions.

### DIRECTORS AND OFFICERS

The names and jurisdictions of residence of our directors and management team, the positions held by them with us and their principal occupations for the past five years are as set forth below. The term of office of the directors expires annually at the time of our annual general meeting. The term of office of each officer expires at the discretion of our Board of Directors.

Name and Municipality of Residence	Current Office with the Company	Principal Occupation Since 2006
<b>Directors</b>		
ROSS J. BEATY <i>British Columbia, Canada</i>	Chairman and Chief Executive Officer (since January 22, 2008)	Chairman and Chief Executive Officer of Alterra since January 2008; Chairman of Pan American Silver Corp. since 1994
DAVID W. CORNHILL <i>Alberta, Canada</i>	Director (since December 1, 2008)	Chairman and Chief Executive Officer of AltaGas Ltd. Income Trust since 1994
DONALD SHUMKA <i>British Columbia, Canada</i>	Director (since January 22, 2008)	President of Walden Management Ltd. since 2004
PAUL B. SWEENEY <i>British Columbia, Canada</i>	Director (since September 11, 2008)	Executive Officer of Plutonic from April 2010 to May 2011; former President of Plutonic from August 2009 to April 2010; former Executive Vice-President Business Development of Plutonic from January 2007 to August 2009; financial consultant from 2005 to January 2007
DONALD A. MCINNES <i>British Columbia, Canada</i>	Director (since May 13, 2011)	Chief Executive Officer and Director of Plutonic since June 1999; Vice-Chairman of Plutonic since October 2007; former President of Plutonic from 1999 to 2007
WALTER T. SEGSWORTH <i>British Columbia, Canada</i>	Director (since May 13, 2011)	Self employed businessman and consulting engineer; Chairman of Plutonic since June 2005
DAVID S. O'BRIEN <i>Ontario, Canada</i>	Director (since May 13, 2011)	Retired business executive since September 2009; former President and Chief Executive Officer of Toronto Hydro Corporation from July 2004 to September 2009
<b>Executive Officers</b>		
JOHN CARSON <i>British Columbia, Canada</i>	Executive Vice President	Executive Vice President of Alterra since February 2011; former Senior Vice President - Project Finance of Noble Environmental Power from July 2009 to February 2011; former Senior Vice President – Finance / Consultant of Terra-Gen Power LLC from May 2008 to July 2009; former Vice President and Senior Vice President – Renewable Energy of GE Financial Services, Inc. from March 2006 to May 2008

Name and Municipality of Residence	Current Office with the Company	Principal Occupation Since 2006
BRUCE D. RIPLEY <i>British Columbia, Canada</i>	Chief Operating Officer	Chief Operating Officer of Alterra since May 2011; President and Chief Operating Officer of Plutonic since April 2010; former Chief Executive Officer of Toba Montrose General Partnership from October 2008 to February 2011; former President and Chief Operating Officer of Plutonic from October 2007 to August 2009; former Executive Vice President, Operations of Plutonic from March 2007 to October 2007; former Vice President, Engineering of BC Hydro from 2004 to 2006
PETER G. WONG <i>British Columbia, Canada</i>	Chief Financial Officer	Chief Financial Officer of Alterra since May 2011; Chief Financial Officer of Plutonic Power Corporation since September 2005
RUPERT A. LEGGE <i>British Columbia, Canada</i>	Executive Vice President, Legal and Corporate Secretary	Executive Vice President, Legal and Corporate Secretary of Alterra since May 2011 and Executive Vice President, Corporate and Legal Affairs of Plutonic since October 2008; former Senior Vice President, Legal Affairs of Plutonic from January 2008 to October 2008; former lawyer with Miller Thomson LLP from 2004 to 2007
DR. CATHERINE HICKSON <i>British Columbia, Canada</i>	Vice-President, Exploration and Chief Geologist	Vice-President, Exploration and Chief Geologist of Alterra since October 2008; former senior Research Scientist, Natural Resources Canada (Geological Survey of Canada), Subdivision head (GSC Vancouver) and Program manager from June 1988 to October 2008
JAY SUTTON <i>British Columbia, Canada</i>	Vice-President, Hydro Power	Vice-President, Hydro Power with Alterra since May 2011 and General Manager of DGP since February 2011; Vice-President, Hydro Power of Plutonic from January 2011 to May 2011; previously Project Director for TMGP from May 2010 to January 2011; Senior Project Manager, Worley Parsons Engineering from January 2006 to May 2010
PAUL RAPP <i>British Columbia, Canada</i>	Vice-President, Wind Power	Vice-President, Wind Power with Alterra since May 2011 and General Manager of DGP since February 2011; Vice-President, Wind Power of Plutonic from January 2011 to May 2011; previously Director, Construction of Plutonic from February 2008 to December 2010; Senior Manager, BC Hydro from 1987 to January 2008

Name and Municipality of Residence	Current Office with the Company	Principal Occupation Since 2006
MONTE MORRISON <i>Nevada, U.S.A</i>	United States Country Manager and Vice-President, Operations	US Country Manager and Vice-President, Operations of Alterra since June 2, 2010; former Vice-President Operations (Soda Lake) from December 2008 to June 2010; former Director of Operations, Renewable Assets at Constellation Energy Corp from 2003 to 2008
ANDERS KRUIS <i>Washington, U.S.A.</i>	Vice-President, Corporate Relations (Interim)	Interim Vice-President, Corporate Relations of Alterra since February 2011; Managing Director, Lily Point LLC since January 2009; former Chief Financial Officer, Stanton Northwest from September 2006 to December 2008; former Vice-President, Capital Markets, Wilkinson Corp. from January 2004 to August 2006

As of June 30, 2011, the directors and executive officers of the Company, as a group, beneficially own directly or indirectly, or exercise control or direction over 131,263,130 common shares representing approximately 28.2% of the Company's issued and outstanding common shares.

### **Committees of the Board of Directors**

Our Board of Directors has established four board committees: an Audit Committee, a Compensation Committee, a Governance and Nominating Committee and a Health and Safety Committee. The information below summarizes the functions of each of the committees in accordance with their charters.

#### **Audit Committee**

##### ***Audit Committee Charter***

Attached as Appendix "A" is the charter for the Company's Audit Committee.

##### ***Composition of the Audit Committee***

The Audit Committee is comprised of Donald Shumka (Chair), Walter Segsworth and David O'Brien, each of whom is independent and financially literate.

##### ***Relevant Education and Experience of the Members of the Audit Committee***

###### ***Donald Shumka***

Donald Shumka graduated from the University of British Columbia with a B.A. in 1964 and from Harvard University with an MBA in 1966.

From 1976 to 1979, Mr. Shumka worked in various positions in the forest industry. From 1979 to 1989 he was Vice-President and Chief Financial Officer of West Fraser Timber Co. Ltd., and from 1989 to 2004 he headed the Forest Products Group for two Canadian investment banks. Mr. Shumka was the Managing Director of Raymond James Ltd. until 2004, and he is currently the President of Walden Management Ltd., a private management company, and a director of Eldorado Gold Corporation, Paladin

Energy Ltd., Lumina Copper Corp and Anfield Nickel Corp. Mr. Shumka is also active in the not-for-profit sector.

*Walter Segsworth*

Walter Segsworth earned a Bachelor of Science degree in Mining Engineering from Michigan Technological University in 1971, and is a registered Professional Engineer in British Columbia. For the first two decades of his career he worked in various technical and operations positions. In 1990 he became President, Chief Executive Officer and a director of Westmin Resources, and in 1998 he became President, Chief Operating Officer and a director of Homestake Mining Company. During his tenures at Westmin Resources and Homestake Mining Company he dealt extensively with financial reporting and carried the ultimate responsibility for the content of the companies' financial statements. Since his retirement from Homestake Mining Company in 2002, Mr. Segsworth has been engaged almost entirely in serving on the boards of companies in the resource sector (currently five) and has been a member of several audit committees. Mr. Segsworth also serves on the board of Science World, where he is a member of the audit committee.

*David O'Brien*

David O'Brien holds a Bachelor Arts degree from the University of Windsor. Mr. O'Brien, who retired in 2009, has over 30 years of managerial experience, including nine years as City Manager for the City of Mississauga (Ontario) and five years as president and chief executive officer of Toronto Hydro Corp. For the past three years Mr. O'Brien has served as a director and chair of the Investment Committee for the OMERS Pension Board, and previously served on the audit committee of the Trillium Health Centre in Mississauga. He is also currently a director of Apex CoVantage, a Washington-based solutions company for smart meter/smart grid platforms.

***Reliance on Certain Exemptions***

The Company's Audit Committee has not relied on any of the exemptions under National Instrument 52-110 during the most recently completed financial year.

***Audit Committee Oversight***

The Board of Directors adopted all recommendations by the audit committee with respect to the nomination and compensation of the external auditor.

***Pre-Approval Policies and Procedures***

The Audit Committee is responsible for overseeing the work of the external auditors and considering whether the provision of non-audit services is consistent with the external auditor's independence. The Audit Committee shall approve in advance all audit and permitted non-audit services with the independent auditors. This includes the terms of engagement and all fees payable.

***External Auditor Service Fees***

Grant Thornton LLP was the Company's external auditor prior to June 9, 2011, after which KPMG LLP was appointed as the Company's external auditor.

The aggregate fees billed by Grant Thornton LLP and KPMG LLP, during the fiscal year ended June 30, 2011 for assurance and related services rendered that are reasonably related to the performance of the audit review of the Company's financial statements for that year were Cdn.\$583,750.

The aggregate fees billed by Grant Thornton LLP and KPMG LLP during the fiscal year ended June 30, 2011 for professional services for tax compliance, tax advice, tax planning and other services were Cdn.\$190,805. Tax services provided included advice in connection with structuring of transactions and review of tax provisions.

Fees payable by Alterra for audit and other services provided by Grant Thornton LLP and KPMG LLP for the year ended June 30, 2011 and by Grant Thornton LLP for the year ended June 30, 2010 were as follows:

	<u>Year ended June 30, 2011</u>	<u>Year ended June 30, 2010</u>
Audit Fees .....	Cdn.\$501,850	Cdn.\$60,100
Audit Related Fees .....	Cdn.\$81,900	Cdn.\$322,300
Tax-Related Fees <sup>(1)</sup> .....	Cdn.\$71,485	Cdn.\$104,877
Other Fees .....	Cdn.\$119,320	Nil
<b>Total:</b> .....	<u>Cdn.\$774,555</u>	<u>Cdn.\$484,277</u>

Note:

(1) Includes fees for professional services rendered for tax compliance, tax advice, tax planning and other related services.

## Compensation Committee

Our Compensation Committee's role is to assist the Board of Directors in fulfilling its responsibilities relating to matters of human resources and compensation and to establish a plan of continuity and development for senior management of Alterra. Our Compensation Committee determines and makes recommendations with respect to all forms of compensation to be granted to our Chief Executive Officer, and reviewing the Chief Executive Officer's recommendations respecting compensation of our senior executives. To fulfil the responsibilities and duties outlined in its charter, our Compensation Committee reviews and approves corporate goals and objectives relevant to compensation, evaluates performance of executives in light of those corporate goals and objectives and make recommendations respecting appointment, compensation and other terms of employment. The Compensation Committee reviews executive compensation disclosure before we publicly disclose any information regarding compensation, and submits a report to the Board of Directors on human resources matters at least annually.

Our Compensation Committee is comprised of three independent directors, David W. Cornhill, Donald Shumka and Walter Segsworth, the latter of whom is the chair of the Compensation Committee.

## Governance and Nominating Committee

Our Governance and Nominating Committee's charter provides that its responsibilities include: (i) establishing and reviewing member characteristics and the size of the Board of Directors; (ii) recommending the remuneration of directors; (iii) monitoring conflicts of interest of both the Board of Directors and management in accordance with our Code of Business Conduct; (iv) evaluating, identifying and recommending nominees to the Board of Directors and to the various committees thereof; (v) reviewing and developing corporate governance guidelines, policies and procedures for the Board of Directors; (vi) monitoring and reviewing the education and development of members of the Board of

Directors; (vii) establishing and implementing evaluation processes for the Board of Directors, its committees and chairs; (viii) reviewing the Board of Directors mandate and the mandates for each committee thereof, together with position descriptions, and ensuring that the Board of Directors and the committees function independently of management; and (ix) receiving reports from the executive directors regarding breaches of the Code of Business Conduct and reporting such breaches to the Board of Directors.

Our Governance and Nominating Committee is comprised of three independent directors, David S. O'Brien, Donald Shumka and David W. Cornhill, the latter of whom is the chair of the Governance and Nominating Committee.

### **Health and Safety Committee**

The Company is committed to the health and safety of its employees, contractors and visitors in our workplace, including office and field locations, by providing a safe and healthy environment in which to work, and the Company has developed an Occupational Health and Safety Policy to facilitate this. The policy provides that the Company will identify and remedy any hazardous workplace conditions, establish safe policies and programs and educate workers by providing information, resources, tools and training necessary so that they can perform their work safely.

The Board of Directors has established a Health and Safety Committee to which it has delegated oversight responsibilities to ensure that the Company maintains the integrity of its health and safety policies and that the Company's activities are conducted in an environmentally responsible manner. The Committee oversees management's health, safety and environmental decision making, encourages, assists and counsels management in maintaining and improving health, safety and environmental performance and refers to the Board any matter likely to require a decision by the Board.

Our Health and Safety Committee is comprised of two directors, Paul Sweeney and Donald A. McInnes, the latter of whom is chair of the Health and Safety Committee.

### **Corporate Cease Trade Orders and Bankruptcies**

None of the Company's directors or executive officers:

- (a) are, as at the date of this Annual Information Form, or have been, within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including the Company) that,
  - (i) was subject to a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for more than 30 consecutive days (an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or
  - (ii) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;
- (b) are, as at the date of this Annual Information Form, or has been within ten years before the date of this Annual Information Form, a director or executive officer of any company

(including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

- (c) have, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the proposed director.

### **Penalties and Sanctions**

To our knowledge, none of our directors or officers have:

- (a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority; or
- (b) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

### **Conflicts of Interest**

To the best of our knowledge, and other than disclosed herein, there are no known existing or potential conflicts of interest among us and our directors, officers or other members of management as a result of their outside business interests except that certain of our directors and officers serve as directors and officers of other companies, and therefore it is possible that a conflict may arise between their duties to us and their duties as a director or officer of such other companies. Conflicts of interest which arise from time to time, if any, will be dealt with in accordance with the provisions of *The Business Corporations Act* (British Columbia). In accordance with *The Business Corporations Act* (British Columbia), directors who have a material interest or any person who is a party to a material contract or proposed material contract with the Company are required, subject to certain exceptions, to disclose those interests and to generally abstain from voting on any resolution to approve the contract. In addition, the directors will be required to act honestly and in good faith with a view to the best interests of the Company. Some of the directors and officers of the Company have or will have either other employment or other business or time restrictions placed on them and accordingly, these directors and officers of the Company will only be able to devote part of their time to the affairs of the Company.

### **LEGAL PROCEEDINGS**

HS Orka previously entered into a conditional PPA with Norðural to sell power from HS Orka's expansion efforts to a new aluminum smelter to be constructed and located in Reykjanesbær, Iceland. The PPA was executed on April 23, 2007 and contained a number of conditions which were not fulfilled by the time set out in the PPA. Accordingly, HS Orka and Alterra hold the view that the PPA has lapsed in accordance with its terms. Norðural disputes this interpretation and maintains that the PPA is a valid agreement. The PPA provides that disputes relating to the PPA are to be resolved by arbitration, and in July 2010 Norðural initiated arbitration proceedings to determine the validity of the PPA. The arbitration hearing was held in Reykjanesbær in May 2011, and a conclusion is expected in October 2011.

Except as disclosed above, we are not the subject of any material legal proceedings, nor are we or any of our properties a party to or the subject of any such proceedings and no such proceedings are known to be contemplated. We are involved in other routine, non-material litigation arising in the ordinary course of our business.

## **RISK FACTORS**

A prospective investor should carefully consider the risk factors set out below.

### **Risks Relating to our Business and Industry**

#### ***New production wells at our Soda Lake Operation may not define sufficient additional and commercially viable geothermal resources to support our planned expansion programs***

Our expansion programs for the production of increased power from our Soda Lake Operation are not assured of success and depend on the successful drilling and discovery of additional geothermal resources to economically generate increased power. Substantial exploration and development work is required in order to determine if sufficient additional economically recoverable and sustainable geothermal resources are located on the lands and leases comprising our Soda Lake Operation to support additional generating and resource capacity and increase nameplate production to realize the full potential of the Soda Lake resource. Increasing the level of production from the Soda Lake Operation and sustaining it over the long term will require drilling step-out wells to discover additional resource areas. The viability of the planned expansion programs at our Soda Lake Operation will depend upon a number of factors which are beyond our control relating to the nature of the geothermal resource defined through drilling these additional production wells, such as heat content (the relevant composition of temperature and pressure), useful life and operational factors relating to the extraction of fluids from the geothermal resource. If sufficient economically recoverable and sustainable geothermal resources are not defined through drilling, our planned expansion programs at the Soda Lake Operation may be scaled back or not proceed altogether, which would, in turn, adversely affect our business, financial condition, future results and cash flow.

#### ***Geothermal exploration and development programs are highly speculative, are characterized by significant inherent risk and costs, and may not be successful***

Our future performance is partially related to our ability to discover and establish economically recoverable and sustainable geothermal resources on our properties through our exploration and development programs. Geothermal exploration and development involves a high degree of risk and few properties that are explored are ultimately developed into generating power plants. There is no assurance that our exploration and development programs will be successful. Substantial exploration and development work is required in order to determine if any economically recoverable and sustainable geothermal resources are located on these exploration properties. Successfully discovering geothermal resources is dependent on a number of factors, including the technical skill of exploration personnel involved. Even in the event commercial quantities of geothermal resources are discovered, it may not be commercially feasible to bring power generation facilities into a state of commercial production from such geothermal resources. The commercial viability of a geothermal resource once discovered is dependent on a number of factors, some of which are particular attributes of the resource, such as heat content (the relevant composition of temperature and pressure), useful life, operational factors relating to the extraction of fluids from the geothermal resource, proximity to infrastructure, capital costs to construct a power plant and related infrastructure and power prices. Many of these factors are beyond our control.

Geothermal exploration and development costs are high and are not fixed. A geothermal resource cannot be relied upon until substantial development, including drilling, has taken place. The costs of development drilling are subject to numerous variables such as unforeseen geologic conditions underground that could result in substantial cost overruns. Drilling at our properties may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.

Our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, many of which are beyond our control, including economic conditions, mechanical problems, title problems, weather conditions, compliance with governmental requirements and shortages or delays of equipment and services. If our drilling activities are not successful, it could materially adversely affect our business, financial condition, future results and cash flow.

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

Our financial performance depends on our successful operation of our power plants. At present we operate a single power plant at our Soda Lake Operation, have an interest in the Svartsengi and Reykjanes power plants, the Toba Montrose Facility and the Dokie Wind Farm. The cost of operation and maintenance and the operating performance of a power plant 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 the plant's equipment or the equipment of the transmission serving utility
- Labour disputes
- Catastrophic events such as fires, explosions, earthquakes, landslides, floods, releases of hazardous materials, severe storms or similar occurrences affecting a power plant, any of the power purchasers from a power plant or third parties providing services to a power plant
- The aging of power plants, which may reduce their operating performance level and increase the cost of their maintenance
- Fluctuations and changes in weather and wind patterns may impact hydro and wind operations, causing fluctuations in yearly operating results

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

***Our geothermal resources may decline over time and may not remain adequate to support the life of our geothermal power plants***

The operation of geothermal power plants depends on the continued availability of adequate geothermal resources. Although we believe our geothermal resources will be fully renewable if managed properly, we cannot be certain that any geothermal resource will remain adequate for the life of a geothermal power plant.

Any geothermal resource may suffer an unexpected decline in capacity to generate electricity. A number of events could cause such a decline or shorten the operational duration of a geothermal resource, which could cause the applicable geothermal resource to become a non-renewable wasting asset. These events include:

- Power generation above the amount that the applicable geothermal resource will support
- Failure to recycle sufficient geothermal fluids to maintain the applicable geothermal resource
- Failure to properly maintain the hydrological balance of the applicable geothermal resource

If the geothermal resources available to a power plant we develop become inadequate, we may be unable to perform under the PPA for the affected power plant, which in turn could reduce our revenues and adversely affect our business, financial condition, future results and cash flow. If we suffer a decline in our geothermal resources, our insurance coverage may not be adequate to cover losses sustained as a result thereof.

#### ***Uncertainty in the calculation of geothermal resources and probabilistic estimates of MW capacity***

There is a degree of uncertainty attributable to the calculation of geothermal resources and probabilistic estimates of MW capacity. Until a geothermal resource is actually accessed and tested by production wells, the temperature and composition of underground fluids must be considered estimates only. In addition, estimates as to the percentage of the heat that can be expected to be recovered at the surface and the efficiency of converting that heat into electrical energy are subject to a number of assumptions including, but not limited to, resource base temperature, areal extent of the geothermal reservoir, thickness of the geothermal reservoir, percentage of resource recovery and the expected lifetime of the geothermal reservoir. If any of these assumptions prove to be materially incorrect, it may affect the MW capacity of a property.

#### ***Geological occurrences beyond our control may compromise our geothermal operations and their capacity to generate power***

In addition to the substantial risk that production wells that are drilled will not be productive or may decline in productivity after commencement of production, hazards such as unusual or unexpected geologic formations, pressures, downhole conditions, mechanical failures, blowouts, cratering, localized ground subsidence, localized ground inflation, explosions, uncontrollable releases or flows of well fluids, pollution and other physical and environmental risks are inherent in geothermal exploration and production. These hazards could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations.

Additionally, active geothermal areas, such as the areas in which our operations and properties 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 PPA 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.

***We may be unable to obtain the financing we need to pursue our growth strategy***

The development of our properties will often require a substantial capital investment. Our continued access to capital through project financing or through credit facilities or other arrangements with acceptable terms is necessary for the success of our growth strategy. Our attempts to secure the necessary capital may not be on favourable terms, or successful at all. Market conditions and other factors may not permit future project and acquisition financings on terms favourable to us. Our ability to arrange for financing on favourable terms is dependent on numerous factors, including general economic and capital market conditions, investor confidence, the continued success of current projects, the credit quality of the project being financed, the political situation in the jurisdiction in which the project is located and the continued existence of tax laws which are conducive to raising capital. If we are unable to secure capital through credit facilities or other arrangements, we may have to finance our projects using equity financing which will have a dilutive effect on our common shares. Also, in the absence of favourable financing or other capital raising options, we may decide not to build new plants or acquire properties from third parties. Any of these alternatives could have a material adverse effect on our growth prospects and financial condition.

Several of our subsidiaries are and will be required to service existing and future indebtedness, and their failure to do so may entitle the lenders to demand repayment and enforce their security against certain project assets.

***It is very costly to place renewable power resources into commercial production***

Construction, equipment and administrative costs associated with placing renewable power resources into commercial production are considerable. Future development and expansion of power production at our properties may result in significantly increased capital costs related to increased production and injection well drilling and higher costs for labour and materials. To fund expenditures of this magnitude, we may have to seek additional financing and sources of capital. There can be no assurance that additional capital can be found and, if found, it may result in us having to substantially reduce our interest in the project.

***We may incur negative operating cash flow***

Revenues from our operating projects may not be sufficient to fund all of our anticipated expansion, development and exploration programs and general and administrative expenses. Our failure to achieve or maintain profitability and positive operating cash flows could have a material adverse effect on our financial condition and results of operations.

***Power prices are subject to dramatic and unpredictable fluctuations***

The market price of power is volatile and cannot be controlled. If the price of electricity should drop significantly, the economic prospects of the development properties that we have an interest in could be significantly reduced or rendered uneconomic. There is no assurance that a profitable market may exist for the sale of renewable power. Factors beyond our control may affect the marketability of any power we could sell from our renewable resource properties. The marketability of renewable power is also affected by numerous other factors beyond our control, including government regulations relating to royalties, allowable production and exporting of energy sources, the effect of which cannot be accurately predicted.

### ***Industry competition may impede our ability to access suitable renewable resources***

Significant and increasing competition exists for the limited number of renewable resource opportunities available. As a result of this competition, some of which is with large established companies with substantial capabilities and greater financial and technical resources than us, we may be unable to acquire additional renewable power operations or properties on terms we consider acceptable. There can be no assurance that our acquisition programs will yield new renewable power operations or properties.

### ***We may be unable to enter into PPAs on terms favourable to us, or at all***

The electrical power generation industry is highly competitive and we may not be able to compete successfully or grow our business. The industry is complex and, depending on the jurisdiction, may be composed of public utility districts, cooperatives and investor-owned power companies. Many of the participants in this industry produce and distribute electricity. Their willingness to purchase electricity from an independent producer may be based on a number of factors and not solely on pricing and surety of supply. If we cannot enter into PPAs on favourable terms to us, or at all, it would negatively impact our revenue and our decisions regarding development of additional properties.

### ***Contractual risks with BC Hydro EPAs***

Subsidiaries of the Company have entered into long-term EPAs with BC Hydro for the Toba Montrose Facility, Dokie Wind Farm and Upper Toba Project, and it is intended that additional long-term EPAs will ultimately be entered into with BC Hydro for the sale of electricity from the Company's other projects in British Columbia. If the Company is unable to negotiate and enter into such EPAs, the development of its projects in British Columbia could be delayed. Furthermore, our revenues from projects in British Columbia are substantially dependent upon a sole customer, BC Hydro. In addition, if the Company is unable to meet its obligations under an EPA, which could result if there is an interruption in electricity generation, a breach of the EPA could occur potentially resulting in liability to the Company.

### ***Weather and long term hydrology data***

The revenues generated by run-of-river systems such as those developed by the Company are proportional to the amount of electricity generated, which is in turn dependent on available water flows. The Company relies on hydrological studies and data to confirm there is sufficient water flow available to generate enough electricity for its projects to be economically viable. Once built, the Company's hydro power projects in British Columbia may be subject to significant variations in precipitation and the amount of snow pack in the watershed, which would affect the water flow necessary for power generation. There can be no assurance that historical water data will remain accurate or that no material hydrological event will occur and have a negative impact on water flows.

### ***Assessment of wind resource and production***

The strength and consistency of the wind resource at the Company's wind projects, including the Dokie Wind Farm, may vary from the estimates set out in the wind study for the project. Weather patterns could change or the historical data could prove to be an inaccurate reflection of the strength and consistency of the wind in the future. The conclusions of wind studies are based on a particular methodology and a set of assumptions about the existence of certain conditions and the continuance of such conditions in the future. The following is a list of considerations which may contribute to actual power production being different, possibly materially, than the power production estimates set out in wind studies:

- The extent to which the limited time period of the site-specific wind data accurately reflects long term wind speeds
- The extent to which historical data accurately reflects the strength and consistency of the wind in the future
- The strength of the correlation between the site-specific wind data and the longer-term regional wind data
- The potential impact of climatic factors
- The accuracy of assumptions on a variety of factors, including but not limited to, weather, icing and soiling of wind turbines, site access, wake and line losses and wind shear
- The accuracy with which anemometers measure wind speed, and the difference between the hub height of the wind turbines and the height of the meteorological towers used for data collection
- The inherent variability of wind speeds
- The lack of independent verification of the turbine power curve provided by the turbine manufacturer
- The potential impact of topographical variations, turbine placement and local conditions, including vegetation
- The inherent uncertainty associated with the specific methodologies and related models, in particular future orientated models, used to project the wind resource
- The potential for electricity losses to occur before delivery

If the actual wind resources for a particular project varies from the estimates in the wind study or wind data collected it could have a material adverse effect on that project and, in turn, on the business, financial position or results of operations of the Company.

#### ***Reliance on single turbine supplier***

The wind turbines for the Dokie Wind Farm have been obtained from one supplier only, Vestas-Canadian Wind Technology Inc. (“**Vestas**”). If for any reason Vestas is unable or unwilling to fulfill its contractual obligations under its warranty and maintenance agreement with DGP, it may have a material adverse effect on the Dokie Wind Farm and in turn, the Company. If Vestas ceases business operations prior to the cessation of operations at the Dokie Wind Farm, spare parts for the Dokie Wind Farm may be unavailable and operation of the wind turbines at the Dokie Wind Farm may be adversely affected, which may have a material adverse effect on the business, financial condition and results of operations of the Dokie Wind Farm and in turn, the Company.

#### ***Turbine design and local climatic conditions***

The Vestas turbines installed at the Dokie Wind Farm were chosen because of their advanced design and their expected ability to withstand local weather conditions. However, there can be no assurance that these turbines will be able to withstand all weather conditions that may be experienced, or that extreme

weather will not otherwise materially impact the production of electricity. While the Vestas turbine's ability to perform in accordance with its power curve has been warranted by Vestas, there is no assurance that such performance will in fact occur. In the event that the turbines do not perform as expected and any deficiencies cannot be corrected in an efficient manner, there may be an adverse effect on the production of electricity by the Dokie Wind Farm. The wind turbines utilized for the Dokie Wind Farm may break down from time to time and may degrade over time. Breakdowns and degradation will adversely affect the operations and increase the expenses of, and decrease the revenues from, the Dokie Wind Farm. In addition, any equipment breakdown after expiry of the applicable warranty period will increase the expenses of the Dokie Wind Farm.

### ***Regulatory and political risks***

The development of the Company's power projects and their future operation are subject to extensive regulation by various federal, provincial and municipal governments, and changes in the policies and laws of any of these governments could have a significant impact on the Company and its projects, including regulations relating to environmental policies and conflicts of interest with other parties and other related matters beyond the direct control of the Company. Specific risks include increases in water rentals, wind participation rent, property and other taxes and changes in regulations which could make it more difficult to obtain necessary permits.

### ***The cancellation or expiry of government initiatives to support renewable power generation may adversely affect our business***

Numerous government initiatives are currently in place, or have been or may be proposed, to support the development of renewable power generation to meet increasing electricity demand. In the United States, current initiatives include: incentives within the United States Internal Revenue Code, such as the investment tax credit ("ITC") and accelerated depreciation allowances; provisions of the *American Recovery and Reinvestment Act of 2009* extending the availability of the production tax credits for geothermal projects placed in service before 2014, increasing the ITC from 10% to 30% of eligible costs, and creating a new grant program for renewable power projects that are placed in service in, or for which construction begins in, 2009 or 2010; and renewable portfolio standards requirements or goals established in 33 states and the District of Columbia. The cancellation or expiry of any one or more of these government initiatives, or the failure of federal or state governments to adopt similar initiatives in the future, may adversely affect our business by increasing the costs for financing or development of geothermal power plants and related transmission facilities, reducing demand for renewable power or lowering power prices.

### ***Environmental and other regulatory requirements may add costs and uncertainty***

Our current and future operations, including exploration and development activities and electricity generation from power plants, require licences and permits from various governmental authorities and such operations are and will be subject to laws and regulations governing exploration and development, geothermal resources, water use, production, wind participation rent, exports, taxes, labour standards, occupational health, waste disposal, toxic substances, land use, environmental protection, project safety and other matters. Companies can experience increased costs, and delays in production and other schedules as a result of the need to comply with applicable laws, regulations, licences and permits. There is no assurance that all approvals or required licences and permits will be obtained. Additional permits, licences and studies, which may include environmental impact studies conducted before licences and permits can be obtained, may be necessary prior to the exploration or development of properties, or the operation of power plants, in which we have interests, and there can be no assurance that we will be able to obtain or maintain all necessary licences or permits that may be required on terms that enable

operations to be conducted at economically justifiable costs. Failure to comply with applicable laws, regulations, licensing or permitting requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment, or remedial actions. We may be required to compensate those suffering loss or damage by reason of our activities, and may have civil or criminal fines or penalties imposed upon us for violations of applicable laws or regulations.

In the state of Nevada, drilling for geothermal resources is governed by specific rules. In particular, Nevada drilling operations are governed by the Division of Minerals (Nevada Administrative Code Chapter 534A). These rules require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters, and, may not allow or may restrict drilling activity, or may require that a geothermal resource be unitized (shared) with adjoining land owners. Comparable laws exist in Italy, and are being developed in Chile and Peru. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating and abandoning our geothermal wells, power plants and other facilities.

Applicable laws and regulations, including environmental requirements and licensing and permitting processes, may require public disclosure and consultation. It is possible that a legal protest could be triggered through one of these requirements or processes that could delay, or require the suspension of, an exploration or development program or the operation of a power plant and increase our costs. Because of these requirements, we could incur liability to governments or third parties for any unlawful discharge of pollutants into the air, soil or water, including responsibility for remediation costs. We could potentially discharge such materials into the environment: from a well or drilling equipment at a drill site; leakage of fluids or airborne pollutants from gathering systems, pipelines, power plants or storage tanks; damage to geothermal wells resulting from accidents during normal operations; and blowouts, cratering and explosions.

No assurance can be given that new laws and regulations will not be enacted or that existing laws and regulations will not be applied in a manner that could limit or curtail our exploration and development programs or our operation of power plants. Amendments to current laws, regulations, licences and permits governing operations and activities of geothermal companies, or more stringent implementation thereof, could have a material adverse impact on us and cause increases in capital expenditures or production costs, or reduction in levels of production, or abandonment, or delays in development of the business.

#### ***The success of our business relies on attracting and retaining key personnel***

We are dependent upon the services of our senior management team. The loss of any of their services could have a material adverse effect upon us.

#### ***Employee recruitment, retention and human error***

Recruiting and retaining qualified personnel is critical to our success. We are dependent on the services of key executives including our Chief Executive Officer and other highly skilled and experienced executives and personnel focused on managing our interests. The number of persons skilled in acquisition, exploration, development and operation of geothermal properties and the development and operation of hydro and wind projects is limited and competition for such persons is intense. As our business activities grow, we will require additional key financial, administrative and technical personnel as well as additional operations staff. There can be no assurance that we will be successful in attracting, training and retaining qualified personnel as competition for persons with these skill sets increase. If we

are not successful in attracting, training and retaining qualified personnel, the efficiency of our operations could be impaired, which could have an adverse impact on our future cash flows, earnings, results of operations and financial condition.

Despite efforts to attract and retain qualified personnel, as well as the retention of qualified consultants, to manage our interests, even when those efforts are successful, people are fallible and human error could result in significant uninsured losses to us. These could include loss or forfeiture of assets for non-payment of fees or taxes, significant tax liabilities in connection with any tax planning effort we might undertake and legal claims for errors or mistakes by our personnel.

***Our officers and directors may have conflicts of interests arising out of their relationships with other companies***

Several of our directors and officers serve (or may agree to serve) as directors or officers of other companies or have significant shareholdings in other companies. To the extent that such other companies may participate in ventures in which we may participate, the directors may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. From time to time several companies may participate in the development of properties or projects thereby allowing for their participation in larger development programs, permitting involvement in a greater number of development programs and reducing financial exposure in respect of any one development program. It may also occur that a particular company will assign all or a portion of its interest in a particular development program to another of these companies due to the financial position of the company making the assignment.

***We may face adverse claims to our title***

Although we have taken reasonable precautions to ensure that legal title to our properties is properly documented, there can be no assurance of title to any of our property interests, or that such title will ultimately be secured. Our property interests may be subject to prior unregistered agreements or transfers or other land claims, and title may be affected by undetected defects and adverse laws and regulations.

Pursuant to the terms of our BLM leases, we are required to conduct our operations on BLM-leased land in a workmanlike manner and in accordance with all applicable laws and BLM directives and to take all mitigating actions required by the BLM to protect the surface of and the environment surrounding the relevant land. Additionally, certain BLM leases contain additional requirements, some of which relate to the mitigation or avoidance of disturbance of any antiquities, cultural values or threatened or endangered plants or animals, 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 adversely affect our business, financial condition, future results and cash flow.

***Developments regarding Aboriginal, First Nations and Indigenous peoples***

We explore and operate in areas inhabited by aboriginal, First Nations, and indigenous people. Developing laws and movements respecting the acquisition of lands and other rights from such people and communities may alter decades old arrangements made by prior owners of our renewable power properties or even those made by us in more recent years. We have used commercially reasonable efforts in its dealing with all aboriginal, First Nations, and indigenous people to ensure all agreements are entered

into in accordance with the laws governing aboriginal, First Nations, and indigenous peoples and their communities but because of complex procedural and administrative requirements in some jurisdictions, there is no guarantee that such agreements will ultimately protect our interest, nor can there be any guarantee that future laws and actions will not have a material adverse effect on our financial position, cash flow and results of operations.

The Company's British Columbia projects may be located on Crown land which is subject to ongoing, unresolved claims by First Nations. The Company's failure to reach an agreement with such First Nations could result in delays to the development of the Company's British Columbia projects.

***Fluctuation in foreign currency exchange rates may affect our financial results***

We maintain accounts in Canadian and U.S. dollars and other currencies. Our operations in the United States, Iceland, Italy and South America make us subject to foreign currency fluctuations. Foreign currency fluctuations are material to the extent that fluctuations between the Canadian and other currencies are material. We do not at present, nor do we plan in the future, to engage in foreign currency transactions to hedge exchange rate risks but we do convert Canadian funds to U.S. dollars anticipating U.S. expenditures.

***We may not be able to successfully integrate businesses or projects that we acquire in the future***

Our business strategy is to expand in the future, including through acquisitions. Integrating acquisition targets is often costly, and we may not be able to successfully integrate acquired companies with their 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:

- the failure of the acquired companies to achieve expected results;
- inability to retain key personnel of acquired companies;
- risks associated with unanticipated events or liabilities; and
- difficulties associated with establishing and maintaining uniform standards, controls, procedures and policies, including accounting and other financial controls and procedures.

***Our insurance policies may be insufficient to cover losses***

As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. We do not fully insure against all risks associated with our business either because such insurance is not available or because the cost of such coverage is considered prohibitive. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our financial condition and results of operations.

***Aluminum price risk***

A significant portion of the revenue of our Icelandic operations is subject to the market price for aluminum. In addition, a portion of the Company's debt obligations are also linked to the market price for aluminum. Accordingly, fluctuations in the market price for aluminum could have a material adverse effect on the Company's financial position.

## **Risks Relating to the Political and Economic Climates of Countries in which we Operate**

### *There are risks associated with inter-regional transmission grids*

The electrical power generated by our operations may be used by consumers in the jurisdiction where such operations are located or sold to other neighbouring jurisdictions through an inter-regional transmission grid. Applicable laws, inter-regional agreements and the structure and functioning of the power markets between a host state and its neighbouring states are all critical to the success of our geothermal projects.

### *Host country economic, social and political conditions can negatively affect our operations*

A number of our geothermal exploration properties are located in Iceland, Chile and Peru. As we conduct exploration and development operations in these foreign countries, we are exposed to a number of risks and uncertainties, including:

- Terrorism and hostage taking
- Military repression
- Expropriation or nationalization without adequate compensation
- Difficulties enforcing judgments obtained in Canadian or United States courts against assets located outside of those jurisdictions
- Labour unrest
- High rates of inflation
- Changes to royalty and tax regimes
- Extreme fluctuations in currency exchange rates
- Volatile local political and economic developments
- Difficulty with understanding and complying with the regulatory and legal framework respecting the ownership and maintenance of geothermal properties and power plants
- Difficulty obtaining key equipment and components for equipment

Host country economic, social and political uncertainty can arise as a result of lack of support for our activities in local communities in the vicinity of our properties. Such uncertainties also arise as a result of the relatively new and evolving promotion of private-sector power development. Though the effects of competition will increase the likelihood of market efficiencies and benefit our properties, elimination of energy cost subsidies may increase the inability of end-use consumers to pay for power and lead to political opposition to privatization initiatives and have an adverse impact on our properties and operations.

## **Risks Relating to the Common Shares and Trading Market**

### ***If our common share price fluctuates, investors could lose a significant part of their investment***

In recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. The market price of our common shares could similarly be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- Changes in securities analysts' recommendations and their estimates of our financial performance
- The public's reaction to our press releases, announcements and filings with securities regulatory authorities and those of its competitors
- Changes in market valuations of similar companies
- Investor perception of our industry or prospects
- Additions or departures of key personnel
- Commencement of or involvement in litigation
- Changes in environmental and other governmental regulations
- Announcements by us or our competitors of strategic alliances, significant contracts, new technologies, acquisitions, commercial relationships, joint ventures or capital commitments
- Variations in our quarterly results of operations or cash flows or those of other companies
- Revenues and operating results failing to meet the expectations of securities analysts or investors in a particular quarter
- Future issuances and sales of our common shares
- Changes in general conditions in the domestic and worldwide economies, financial markets or the power industry

The impact of any of these risks and other factors beyond our control could cause the market price of our common shares to decline significantly. In particular, the market price for our common shares may be influenced by variations in electricity prices, which are highly volatile.

### ***We currently have no dividend payment policy***

We have not declared or paid any dividends on our common shares and do not currently have a policy on the payment of dividends. The payment of any future dividends will depend upon earnings and our financial condition, current and anticipated cash needs and such other factors as our Board of Directors considers appropriate.

***The issuance of additional equity securities may negatively impact the trading price of our common shares***

We may issue equity securities to finance our activities in the future. In addition, outstanding options or warrants to purchase our common shares may be exercised, resulting in the issuance of additional common shares. Our issuance of additional equity securities or a perception that such an issuance may occur could have a negative impact on the trading price of our common shares.

***Current global financial conditions have been subject to increased volatility***

Current global financial conditions have been subject to increased volatility and numerous financial institutions have either gone into bankruptcy or have had to be rescued by governmental authorities. These factors may impact our ability to obtain equity or debt financing in the future and, if obtained, on terms favourable to us. If these increased levels of volatility and market turmoil continue, our operations could be adversely impacted and the trading price of our common shares could be adversely affected.

**INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

Other than as disclosed below and elsewhere in this Annual Information Form, none of our directors or senior officers or any shareholder holding, on record or beneficially, directly or indirectly, more than 10% of the issued common shares, or any of their respective associates or affiliates, had any material interest, directly or indirectly, in any material transaction with us within the three preceding years or in any proposed transaction which has materially affected us or would materially affect us.

Pursuant to the terms of the credit agreement (the “**2008 Credit Agreement**”) dated August 25, 2008 between Magma and Kestrel Holdings Ltd. (“**Kestrel**”), a private company wholly-owned by our Chairman and Chief Executive Officer, Ross J. Beaty, Kestrel has agreed to lend us an aggregate principal amount of up to Cdn.\$20,000,000 to be used by us to pay amounts coming due in connection with the acquisition of the Soda Lake Operation, to pay our obligations respecting certain land acquisitions, and to fund our general working capital requirements.

The principal amount of each initial advance and each subsequent advance, together with all accrued but unpaid interest and other costs or charges payable under the 2008 Credit Agreement will be immediately due and payable by us to Kestrel on the earlier of 12 months from the date of the initial advance under the 2008 Credit Agreement, the date of any change of control of Magma, any initial public offering of Magma, or the occurrence of an event of default, as defined in the 2008 Credit Agreement.

We may prepay the facility in whole at any time before maturity, without notice or penalty. Interest will accrue on the outstanding balance under the 2008 Credit Agreement as of the date of the initial advance, at the rate of eight percent per annum. We will pay a standby fee to Kestrel in the amount of one percent of the total facility upon the initial advance under the 2008 Credit Agreement and a non-refundable drawdown fee to Kestrel in the amount of three percent of each advance under the 2008 Credit Agreement. We will also pay Kestrel’s legal fees and other costs, charges and expenses of and incidental to the preparation, execution and completion of the 2008 Credit Agreement. In the event any amount remains outstanding under the terms of the 2008 Credit Agreement after December 31, 2009, Kestrel has the option to convert any such amount into common shares at a rate per share equal to Cdn.\$1.50 per common share, subject to certain adjustments. In the event any amount remains outstanding under the terms of the 2008 Credit Agreement after December 31, 2009, we shall also have the option to convert up to 55 percent or any such lesser amount into common shares at Cdn.\$1.50 per common share, subject to certain adjustments. As of the date of this Annual Information Form all amounts advanced under the 2008 Credit Agreement have been repaid in full.

Pursuant to the terms of the 2010 Credit Agreement dated July 5, 2010, an agreement with Ross Beaty, the Company's Chairman and Chief Executive Officer, the Company is able to borrow up to Cdn.\$10,000,000 to pay amounts coming due by the Company to Geysir Green respecting the Company's acquisition of HS Orka of shares of HS Orka, and to fund general working capital requirements. All funds advanced under the 2010 Credit Agreement are repayable on the earlier of twelve months from the date of the initial advance, a change of control of the Company or on a default by Magma. Interest at the rate of 8% per annum, compounded daily, is payable monthly commencing on July 30, 2010. In addition, a standby fee in the amount of 1% of the credit facility and a drawdown fee in the amount of 1.5% of the amount advanced is payable in cash. As of the date of this Annual Information Form, the full principal amount of the credit facility has been advanced to the Company to be used in connection with the acquisition of shares of HS Orka.

On June 30, 2011, Paul Sweeney, a director of Alterra, received 150,000 common shares, Cdn.\$100,000 and a grant of 150,000 options under Alterra's Incentive Stock Option and Stock Bonus Plan as consideration for the termination of his employment agreement with Plutonic.

### **TRANSFER AGENT AND REGISTRAR**

The registrar and transfer agent for our common shares is Computershare Investor Services Inc. at its principal offices in Vancouver, British Columbia.

### **MATERIAL CONTRACTS**

Our only material contracts entered into since the beginning of the last financial year ending before the date of this Annual Information Form, and our material contracts entered into before the beginning of the last financial year ending before the date of this Annual Information Form that are still in effect, other than contracts entered into in the ordinary course of business, are as follows:

- Share purchase agreement among the Company, Magma Energy Sweden A.B. and Geysir Green dated May 16, 2010, relating to the Company's acquisition of HS Orka, the terms of which are described in this Annual Information Form under the heading "General Developments of the Business".
- Arrangement Agreement with Plutonic Power Corporation dated March 7, 2011, and related supporting documents, the terms of which are described under the heading "General Development of the Business".
- Impact Benefit Agreement with Homalco Indian Band dated July 15, 2011, the terms of which are described under the heading "Properties in Canada – Bute Project".

Copies of the above material contracts are available on SEDAR located at [www.sedar.com](http://www.sedar.com).

### **INTEREST OF EXPERTS**

No person or company whose profession or business who is named as having prepared or certified a statement, report, valuation or opinion described or included in this Annual Information Form holds any beneficial interest, direct or indirect, in any of our securities or property or in the securities or properties of any of our associates, or affiliates and no such person is expected to be elected, appointed or employed as one of our directors, officers or employees or as a director, officer or employee of any of our associates or affiliates and no such person is one of our promoters or the promoter of one of our associates or affiliates. In particular, KPMG LLP have informed us that they are independent with respect to Alterra

within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of British Columbia.

Information of an economic, scientific or technical nature regarding the geothermal resources and properties of HS Orka included in this Annual Information Form is based upon the HS Orka Report. The HS Orka Report was prepared by Mannvit hf. Information of an economic scientific or technical nature regarding the geothermal resources of the Soda Lake Operation is based upon the Soda Lake Report. The Soda Lake Report was prepared by GeothermEx. Information of a scientific or technical nature regarding the McCoy, Thermo Hot Springs and Desert Queen properties included in this Annual Information Form is based upon each of the McCoy Report, Thermo Hot Springs Report and Desert Queen Report, respectively. Each of the McCoy Report, Thermo Hot Springs Report and Desert Queen Report were prepared by J. Douglas Walker, Ph.D. Information of an economic, scientific or technical nature regarding the geothermal resources of the Mariposa Project is based upon the Mariposa Report. The Mariposa Report was prepared by Phillip James White of SKM. See “Scientific and Technical Information”.

The authors referenced above are independent of the Company and do not have an interest in the property of the Company.

#### **ADDITIONAL INFORMATION**

Additional information relating to the Company may be found on SEDAR at [www.sedar.com](http://www.sedar.com). Additional information including directors’ and officers’ remuneration and indebtedness, principal holders of the Company’s securities and securities authorized for issuance under equity compensation plans will be contained in the Company’s information circular to be prepared in connection with the Company’s annual meeting of shareholders and will be available on SEDAR at [www.sedar.com](http://www.sedar.com). Additional financial information is provided in the Company’s financial statements and management’s discussion and analysis for the financial year ended June 30, 2011, which are also available on SEDAR.

## GLOSSARY OF TERMS

In this Annual Information Form, the following terms shall have the meanings set forth below, unless otherwise indicated or the context otherwise requires:

“**2010 Credit Agreement**” means the credit agreement dated July 5, 2010 between Magma and Ross Beaty.

“**ABWGP**” means ABW Solar General Partnership.

“**Australian Code**” means the Australian Geothermal Reporting Code.

“**BC Hydro**” means the British Columbia Hydro and Power Authority.

“**BCUC**” means the British Columbia Utilities Commission.

“**BLM**” means U.S. Bureau of Land Management.

“**Bute Inlet Project**” means a group of sites for proposed run-of-river generation facilities located in the Homathko, Southgate, Orford, Bear and Teaquahan river drainage basins, all of which are in the vicinity of Bute Inlet, together with the transmission line to be built from the Bute Inlet Project to Malaspina to interconnect with the BC Hydro transmission grid.

“°C” means degrees Celsius.

“**Canadian Code**” means the Canadian Geothermal Code for Public Reporting.

“**Cdn.\$**” means Canadian dollars.

“**CEA**” means the British Columbia *Clean Energy Act*.

“**CEAA**” means the Canadian Environmental Assessment Agency.

“**Desert Queen Report**” means the Independent Technical Report Resource Evaluation of the Desert Queen Geothermal Project, Churchill County, Nevada dated May 12, 2009 prepared by Dr. J. Douglas Walker (Ph.D.).

“**DGP**” means Dokie General Partnership.

“**dollars**” or “**\$**” means United States dollars.

“**Dokie Wind Farm**” means the wind farm located west of Chetwynd, British Columbia and the accompanying transmission line from the wind farm to the Dokie interconnection site owned by BC Hydro.

“**EAO**” means Environmental Assessment Office.

“**EPA**” means electricity purchase agreement with BC Hydro.

“°F” means degrees Fahrenheit.

“**First Solar**” means First Solar, Inc.

“**GeothermEx**” means GeothermEx Inc.

“**Geysir Green**” means Geysir Green Energy ehf.

“**HS Orka**” means HS Orka hf.

“**HS Orka Report**” means the Geothermal Resources and Properties of HS Orka, Reykjanes Peninsula, Iceland: Independent Technical Report dated January 29, 2010 prepared by Mannvit hf.

“**INGEMMET**” means the Instituto Geológico Minero Y Metalúrgico.

“**Initial Investors**” has the meaning ascribed to the term under “Escrowed Securities”.

“**Initially Offered Shares**” has the meaning ascribed to such term under “Escrowed Securities”.

“**ISK**” means Icelandic Krona.

“**ITC**” means investment tax credit.

“**Jardvarmi**” means Jardvarmi slhf.

“**Kestrel**” means Kestrel Holdings Ltd.

“**kV**” means kiloVolt (1000 volts).

“**Magma**” means Magma Energy Corp., the Company’s name prior to it being changed to Alterra Power Corp.

“**Magma Sweden**” means Magma Energy Sweden A.B.

“**Mariposa Project**” means the Laguna del Maule and Pellado concessions in Chile.

“**Mariposa Report**” means the Mariposa Geothermal Resource, Laguna del Maule and Pellado Concessions, Chile dated July 19, 2010 prepared by Philip James White of Sinclair Knight Merz Limited.

“**McCoy Report**” means the Independent Technical Report Resource Evaluation of the McCoy Geothermal Project, Churchill and Landers Counties, Nevada dated April 29, 2009 prepared by Dr. J. Douglas Walker (Ph.D.).

“**MEM**” means the Peruvian Ministry of Energy and Mines.

“**MMS**” means the U.S. Minerals Management Service.

“**MT**” means magnetotelluric.

“**MW**” means megawatt; one million watts.

“**Na/K/Ca**” refers to a sodium-potassium-calcium geothermometer that is a geochemical calculation used to estimate geothermal reservoir temperature from analytical results of liquid samples.

“**NI 43-101**” means National Instrument 43-101 – *Standards of Disclosure for Mineral Projects*.

“**NI 51-101**” means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*.

“**Norðural**” means Norðural Helguvik sf.

“**NV Energy**” means NV Energy Company.

“**Plan**” means the BC Energy Plan.

“**Plutonic**” means Plutonic Power Corporation.

“**PPA**” means power purchase agreement.

“**SEDAR**” means the system for electronic document analysis and retrieval.

“**SKM**” means Sinclair Knight Merz Limited.

“**Soda Lake Report**” means the Independent Technical Report: Geothermal Resources and Reserves at Soda Lake Project, Churchill County, Nevada USA dated April, 2010 prepared by GeothermEx.

“**Thermo Hot Springs Report**” means the Independent Technical Report Resource Evaluation of the Thermo Hot Springs Geothermal Project, Beaver County, Utah dated May 15, 2009 prepared by Dr. J. Douglas Walker (Ph.D.).

“**TMGP**” means Toba Montrose General Partnership.

“**Toba Montrose Facility**” means the combined East Toba River and Montrose Creek run-of-river generation facilities and the accompanying transmission line from the facilities to Sallery Bay on Jervis Inlet.

“**TSX**” means the Toronto Stock Exchange.

“**Upper Toba Project**” means the two sites for proposed run-of-river generation facilities located on Jimmie Creek and the Upper Toba River, which will utilize the same transmission line being used for the Toba Montrose Facility.

“**UTGP**” means Upper Toba General Partnership.

“**Vestas**” means Vestas Canadian Wind Technology Inc.

“**WTGs**” means wind turbine generators.

#### METRIC CONVERSION TABLE

<u>Metric Unit</u>	<u>U.S. Measure</u>	<u>U.S. Measure</u>	<u>Metric Unit</u>
1 hectare .....	2.471 acres	1 acre .....	0.4047 hectares
1 metre .....	3.2881 feet	1 foot .....	0.3048 metres
1 kilometre .....	0.621 miles	1 mile.....	1.609 kilometres

## APPENDIX “A”

### AUDIT COMMITTEE CHARTER

#### 1. PURPOSE

The purpose of the audit committee (the “**Committee**”) is to assist the board of directors (the “**board**”) in fulfilling its oversight responsibilities for (a) the accounting and financial reporting processes; (b) the internal controls; (c) the external auditors, including performance, qualifications, independence and their audit of the Company’s financial statements; and (d) the performance of the Company’s internal audit function.

#### 2. COMPOSITION

- (a) The Committee shall be composed of three independent directors and shall not include any director employed by the Company.
- (b) The board shall appoint annually, from among its members, the members of the Committee and its chair.
- (c) The members and the chair of the Committee shall serve one-year terms and are permitted to serve an unlimited number of consecutive terms.
- (d) Each member of the Committee shall be financially literate, meaning that each member must have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are reasonably comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company’s financial statements.

#### 3. MEETING

- (a) The Committee shall meet at least four times per year and any member may call special meetings as required.
- (b) A quorum at meetings of the Committee shall be two members. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present.
- (c) The chair of the Committee shall, in consultation with management and the auditors, establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting.
- (d) The minutes of the Committee meetings shall accurately record the decisions reached and shall be distributed to all directors with copies to the chief financial officer and the external auditors.

#### 4. DUTIES AND RESPONSIBILITIES

##### (a) Financial Information

The Committee shall review:

- (i) the annual financial statements and recommend their approval to the board, after discussing matters such as the selection of accounting policies, major accounting judgements, accruals and estimates with management;
- (ii) other financial information included in the annual report and any other reports to shareholders and others;
- (iii) financial information in any annual information form, management proxy circular, prospectus or other offering document, material change report or business acquisition report;
- (iv) management's discussions and analysis contained in the annual report and quarterly statements, if any;
- (v) earnings press releases and any news release regarding financial results or containing earnings guidance before being released to the public;
- (vi) filings to the securities regulators containing financial information; and
- (vii) audits and reviews of financial statements of the Company and its subsidiaries.

**(b) External Audit**

The Committee shall:

- (i) recommend to the board the external auditors to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company and the compensation of the external auditors;
- (ii) review and approve the Company's hiring policies regarding partners, employees and former partners or employees of the present or former external auditors of the Company;
- (iii) at least annually, review the qualifications and performance of the lead partners of the external auditors and determine whether it is appropriate to adopt or continue a policy of rotating the lead partner of the external auditors;
- (iv) review and pre-approve all audit and non-audit service engagement fees and terms in accordance with applicable law, including those provided to the subsidiaries of the Company by the external auditors or any other person in its capacity as external auditors of such subsidiary;
- (v) review the planning and results of the external audit, including:
  - A. the auditor's engagement letter;
  - B. the reasonableness of the estimated audit fees;
  - C. the scope of the audit, including materiality, locations to be visited, audit reports required, areas of audit risk, timetable, deadlines and coordination with internal audit;
  - D. the post-audit management letter together with management's response;

- E. the form of the audit report;
  - F. any other related audit engagements (e.g. audit of the company pension plan);
  - G. non-audit services performed by the auditor;
  - H. assessing the auditor's performance; and
  - I. meeting privately with the auditors to discuss pertinent matters, including the quality of accounting personnel;
- (vi) discuss with management and the external auditors any significant financial reporting issues considered during the fiscal period and the method of resolution and resolve disagreements between management and the external auditors regarding financial reporting; and
  - (vii) review with management and the external auditors any items of concern, any proposed changes in the selection or application of major accounting policies and the reasons for the change, any identified risks and uncertainties, and any issues requiring management judgment, to the extent that the foregoing may be material to financial reporting.

**(c) Interim Financial Statements**

The Committee shall:

- (i) obtain reasonable assurance on the process for preparing reliable quarterly interim financial statements from discussions with management and, where appropriate, reports from the external and internal auditors;
- (ii) review and discuss with management and the external auditors all interim unaudited financial statements and quarterly reports and related interim management discussion and analysis and make recommendations to the board with respect to the approval thereof, before being released to the public; and
- (iii) obtain reasonable assurance from management about the process for ensuring the reliability of other public disclosure documents that contain audited and unaudited interim financial information.

**(d) Accounting System and Internal Controls**

The Committee shall:

- (i) obtain reasonable assurance from discussions with and/or reports from management and reports from external and internal auditors that the Company's accounting systems are reliable and that the prescribed internal controls are operating effectively;
- (ii) direct the auditors' examinations to particular areas;
- (iii) request the auditors to undertake special examinations (e.g., review compliance with conflict of interest policies);

- (iv) review control weaknesses identified by the external and internal auditors, together with management's response;
- (v) review the appointments of the chief financial officer and key financial executives; and
- (vi) review accounting and financial human resources and succession planning within the Company.

**(e) Internal Audit**

The Committee shall:

- (i) review the terms of reference of the internal audit function and the appointment or removal of the director of the internal audit;
- (ii) review the resources, budget, reporting relationships and planned activities of the internal audit function; and
- (iii) review internal audit findings and determine that they are being properly followed-up.

**(f) Compliance**

The Committee shall:

- (i) monitor compliance by the Company of the governing laws and any regulatory requirements, including all payments and remittances required to be made in accordance with applicable law;
- (ii) monitor compliance by the Company of the terms of the International Business Conduct Policy and report periodically to the board thereon; and
- (iii) establish and oversee the procedures in the Code of Business Conduct and the Company's Whistleblower Policy to address:
  - A. the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters; and
  - B. confidential, anonymous submissions by employees of concerns regarding questionable accounting and auditing matters.

**(g) Other Responsibilities**

The Committee's additional responsibilities to be defined as required, but may include:

- (i) monitoring compliance with the corporate code of conduct;
- (ii) investigating fraud, illegal acts or conflicts of interest;
- (iii) discussing selected issues with corporate counsel; and
- (iv) reviewing compliance with environmental codes of conduct and legislation.

**(h) Liaison with Other Financial Officer/Audit Committees of Subsidiary Companies**

The Committee shall:

- (i) review the mandate and terms of reference of a subsidiary's audit committee;
- (ii) review the financial report(s) of the subsidiary's audit committee to its board of directors; and
- (iii) follow-up, as appropriate, with management, the chairperson of the audit committee or the audit partner of the subsidiary on any matters of concern.

**(i) Reporting**

The Committee shall:

- (i) report, through the chairperson, to the board following each meeting on the major discussions and decisions made by the Committee;
- (ii) report annually, through the board, to the shareholders on the Committee's responsibilities and how it has discharged them; and
- (iii) review the Committee's terms of reference annually and propose recommended changes to the board.

**5. REGULATIONS**

- (a) The Committee shall have the power, authority and discretion delegated to it by the board which shall not include the power to change the membership of or fill vacancies in the Committee.
- (b) The Committee shall conform to the regulations which may from time to time be imposed upon it by the board.
- (c) A resolution approved in writing by the members of the Committee shall be valid and effective as if it had been passed at a duly called meeting. Such resolution shall be filed with the minutes of the proceedings of the Committee and shall be effective on the date stated thereon or on the latest date stated in any counterpart.
- (d) The board shall have the power at any time to revoke or override the authority given to or acts done by the Committee except as to acts done before such revocation or act of overriding and to terminate the appointment or change the membership of the Committee or fill vacancies in it as it shall see fit.
- (e) The Committee shall have unrestricted and unfettered access to all Company personnel and documents and shall be provided with the resources necessary to carry out its responsibilities.
- (f) The Committee shall have the resources and authority appropriate to discharge its duties and responsibilities, including the authority to:

- (i) engage independent counsel, or other advisors, as it determines necessary to carry out its duties;
  - (ii) to select and direct the payment of the compensation for any independent counsel or other advisor engaged by the Committee; and
  - (iii) to communicate directly with the internal and external auditors.
- (g) The Committee shall participate in an annual performance evaluation by the governance and nominating committee, the results of which will be reviewed by the board.