ATLANTIC POWER CORP
Form 10-12B/A
June 16, 2010

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Table of Contents

As filed with the Securities and Exchange Commission on June 16, 2010

File No. 001-34691

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

Amendment No. 2
to

FORM 10

GENERAL FORM FOR REGISTRATION OF SECURITIES
PURSUANT TO SECTION 12(b) OR 12(g) OF
THE SECURITIES EXCHANGE ACT OF 1934

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada	**55-0886410**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 Clarendon Street, Floor 25 Boston, Massachusetts, USA	**02116**
(Address of Principal Executive Office)	(Zip Code)

Registrant's telephone number, including area code:
(617) 977-2400

Securities to be registered pursuant to Section 12(b) of the Act:

Title of each class to be registered	**Name of each exchange on which each class is to be registered**
Common Stock, no par value	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act:
None

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller reporting company o

Table of Contents

TABLE OF CONTENTS

Table of Contents

GENERAL

Certain capitalized terms used in this registration statement have the meaning set out under "Glossary of Terms." In this registration statement, references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$" and "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

Unless otherwise stated, or the context otherwise requires, references in this registration statement to "we," "us," "our" and "Atlantic Power" refer to Atlantic Power Corporation, those entities owned or controlled by Atlantic Power Corporation and predecessors of Atlantic Power Corporation.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this registration statement, including documents incorporated by reference herein, constitute "forward-looking statements." Forward-looking statements generally can be identified by the use of forward-looking terminology such as "outlook," "objective," "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "should," "plans," or "continue," or similar expressions suggesting future outcomes or events. Examples of such statements in this registration statement include, but are not limited to, statements with respect to the following:

- expected opportunities for accretive acquisitions;
- our planned application to have our common shares listed on the New York Stock Exchange;
- the amount of distributions expected to be received from the projects for the full year 2010;
- estimated net cash tax refund in 2010;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012; and
- the expected resumption of distributions from our Chambers and Selkirk projects in 2011.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this registration statement. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk Factors." Our business is both competitive and subject to various risks.

These risks include, without limitation:

- a reduction in revenue upon expiration or termination of power purchase agreements;
- the dependence of our projects on their electricity, thermal energy and transmission services customers;

exposure of certain of our projects to fluctuations in the price of electricity;

projects not operating to plan;

the impact of significant environmental and other regulations on our projects;

increased competition, including for acquisitions; and

our limited control over the operation of certain minority-owned projects.

Table of Contents

Other factors, such as general economic conditions, including exchange rate fluctuations, also may have an effect on the results of our operations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf. For a description of risks that could cause our actual results to materially differ from our current expectations, please see "Risk Factors" in this registration statement.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric capacity and energy prices or cash flows that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this registration statement are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this registration statement may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this registration statement.

These forward-looking statements are made as of the date of this registration statement and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

Table of Contents

ITEM 1. BUSINESS.

OVERVIEW

Atlantic Power Corporation is an independent power producer, with power projects located in major markets in the United States. Our current portfolio consists of interests in 12 operational power generation projects across eight states, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW") in which our ownership interest is approximately 807 MW.

The following map shows the location of our projects, including joint venture interests, across the United States:

We sell the capacity and power from our projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2010 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial purchasers. The transmission system rights (or "TSRs") we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our coal and natural gas-powered projects generally operate pursuant to long-term supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power business to operate and maintain our projects, including Caithness Energy, LLC, Cogentrix Energy, Inc. and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Atlantic Power Corporation is organized under the laws of the Province of British Columbia. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8

Table of Contents

and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our website is atlanticpower.com. Information contained on our website is not part of this registration statement.

We completed our initial public offering on the Toronto Stock Exchange (TSX: ATP) in November 2004 and have applied to have our common shares listed on the New York Stock Exchange under the symbol [" "].

HISTORY OF OUR COMPANY

Atlantic Power Corporation is a Canadian corporation that was formed in 2004. We completed our initial public offering on the Toronto Stock Exchange in November 2004. At the time of the IPO, our public security was an Income Participating Security ("IPS"). Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. In the fourth quarter of 2009, we converted to a traditional common share company through a shareholder approved plan of arrangement in which each IPS was exchanged for our new common share. Our new common shares were listed and posted for trading on the Toronto Stock Exchange commencing on December 2, 2009 and trade under the symbol "ATP", and the former IPSs, which traded under the symbol "ATP.UN", were delisted at that time.

The following timeline illustrates significant events in the development of our business since the IPO. Further details about these events are included below:

We used the proceeds from our IPO to acquire a 58% interest in Atlantic Power Holdings, LLC (now Atlantic Power Holdings, Inc., which we refer to herein as "Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC and from Caithness Energy, LLC. Until December 31, 2009, we were externally managed by Atlantic Power Management, LLC, an affiliate of ArcLight. Under this external management arrangement, ArcLight provided administrative and office support services to us and was required to give us the opportunity to pursue investment opportunities that did not fit ArcLight's investment guidelines for its private equity funds. At the time of our IPO, Atlantic Holdings was granted a right of first offer related to ArcLight's interest in 11 power generating

Table of Contents

projects. Our acquisitions of Epsilon Power Partners in 2005 and Auburndale Power Partners, L.P. in 2008 were completed under the terms of this right of first offer, which has since expired.

In August 2005, we acquired Epsilon Power Partners, LLC, which owns a 40% interest in the Chambers project, for approximately $63 million in cash and the assumption of $43 million in non-recourse debt.

In September 2006, we acquired 100% of the equity interests in Trans-Elect NTD Holdings Path 15, LLC (Path 15), which has since been renamed Atlantic Path 15 Holdings, LLC, which indirectly owns approximately 72% of the transmission system rights in the transmission line upgrade along the Path 15 transmission corridor located in central California. The purchase price was approximately $78.4 million.

In December 2006, we completed a private placement of 8,600,000 IPSs and Cdn$3.0 million principal amount of separate subordinated notes to three institutional investors. In February 2007, we used the net proceeds of the private placement to increase our ownership in Atlantic Holdings to 100%.

In December 2007, we increased our ownership interest in the Pasco project from 50% to 100%.

In November 2008, we acquired a 100% ownership interest in Auburndale Power Partners, L.P, which owns the Auburndale project for a purchase price of $139.9 million, subject to customary adjustments for working capital. The acquisition was funded with cash on hand, a $55 million borrowing under our credit facility and non-recourse acquisition debt of $35 million. The non-recourse acquisition debt associated with this transaction amortizes fully over the remaining term of the project's power purchase agreement.

In the first quarter of 2009, we transferred our remaining net interest in Onondaga Cogeneration Limited Partnership, at net book value, into a 50% owned joint venture, Onondaga Renewables, LLC, which is engaged in the redevelopment of the Onondaga project into a 40 MW biomass power plant.

In March 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina corporation. Rollcast is a developer of biomass power plants in the southeastern U.S. with five, 50 MW projects in various stages of development. In March 2010, we agreed to invest an additional $2.0 million to increase our ownership interest in Rollcast to 60%. Under the terms of the agreement, $1.2 million of the investment was made in March 2010 and the remaining $0.8 million was made in April 2010. As a result of this additional investment, we began to consolidate our investment in Rollcast beginning March 1, 2010. In April 2010, Rollcast signed an agreement with two banks to co-arrange project-level debt financing and entered into a construction agreement for its first 50 MW biomass project in Barnesville, Georgia.

In October 2009, we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreements with us, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. In connection with the termination of the management agreements, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its officers.

OUR COMPETITIVE STRENGTHS

Diversified Projects. Our power generation projects have an aggregate gross electric generation capacity of approximately 1,823 MW, and our net ownership interest in the electric generation capacity of these projects is approximately 807 MW. Our power generation projects are diversified by geographic location, electricity and steam customers, and project operators. These projects are generally located in the deregulated and more liquid electricity markets of New

Table of Contents

England, New York, Mid-Atlantic, California and Texas, or are located in regions of relatively high electricity demand growth such as Florida and New Mexico.

Our power transmission project, known as the Path 15 project, is an 84-mile, 500-kilovolt transmission line built in order to alleviate north-south transmission congestion in California. It is a traditional rate-base asset whose revenues are regulated by the Federal Energy Regulatory Commission ("FERC") and is operated by the Western Area Power Administration, a U.S. Federal power agency.

Strong Customer Base. Our customers are generally large utilities, and other parties with investment-grade credit ratings. The largest customers of our power generation projects are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 40%, 15% and 11%, respectively, of the net electric generation capacity of our projects. No other electric customer purchases more than 7% of the net electric generation capacity of our power generation projects.

Leading Third-Party Managers. Our power generation projects rely on a number of different operators for their operation, which are generally recognized leaders in the independent power business. Affiliates of Caithness Energy, LLC, Cogentrix Energy, Inc. and Babcock and Wilcox Power Generation Group, Inc. operate projects representing approximately 49%, 21% and 9%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 8% of the net electric generation capacity of our power generation projects.

Stability of Project Cash Flow. Each of our power generation projects has been in operation for over ten years. Cash flows from each project are generally supported by energy sales contracts with investment-grade utilities and other sophisticated counterparties. We believe that each project's combination of PPA(s), fuel supply agreement(s) and/or commodity hedges help stabilize operating margins as fuel prices fluctuate.

OUR OBJECTIVES AND BUSINESS STRATEGY

Our objectives include maintaining the stability and sustainability of dividends to shareholders and to maximize the value of our company. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of the projects and on pursuing additional acquisitions primarily in the electric power industry in the U.S. and Canada.

Organic Growth

We intend to enhance the operation and financial performance of our projects through:

optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, and operations and maintenance agreements;

achievement of improved operating efficiencies;

upgrade or enhancement of existing equipment or plant configurations; and

expansion of existing projects.

Successfully extending PPAs and fuel agreements may facilitate refinancings that provide capital to fund growth opportunities.

Extending PPAs Following Their Expiration

PPAs in our portfolio have expiration dates ranging from 2010 to 2037. In each case, we plan for expirations by evaluating various options in the market for maximizing project cash flows. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations

Table of Contents

with the original purchasing utility for PPA extensions, arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. We do not assume that pricing under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

Acquisition and Investment Strategy

We believe that new electricity generation projects will be required in the United States and Canada over the next several years as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. There is also a very active secondary market for existing projects. We intend to expand our operations by making accretive acquisitions with a focus on power generation, transmission, distribution and related facilities in the United States and Canada. We may also invest in other forms of energy-related projects, utility projects and infrastructure projects, as well as additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. Since the time of our initial public offering on the Toronto Stock Exchange in 2004, we have twice acquired the interest of another partner in one of our existing projects and will continue to look for such opportunities.

Our senior management has significant experience in the independent power industry and we believe the experience, reputation and industry relationships of our management team will provide us with unique access to future acquisition opportunities.

Acquisition Guidelines

We use the following general guidelines when reviewing and evaluating possible acquisitions:

- each acquisition or investment should result in an increase in cash available for distribution to shareholders;
- in the case of an acquisition of power generation facilities, facilities with long-term PPAs with major electrical utilities or other creditworthy customers will be preferred; and, for facilities without such agreements, market electricity price assumptions used in acquisition evaluations will be obtained from a recognized independent source; and
- in the case of an acquisition of a power generation facility, the expected useful life of the facility and associated structures will, with regular maintenance, be long enough to conform with our objective of providing stable long-term dividends to shareholders.

POWER INDUSTRY OVERVIEW

Historically, the North American electricity industry was characterized by vertically-integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers.

In the independent power generation sector, electricity is generated from a number of sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. According to the North American Electric Reliability Council's Long-Term Reliability Assessment, published in December 2009, summer peak demand within the United States in the ten-year period from 2009 through 2018 is projected to increase 14.8%, while winter peak demand in Canada is projected to increase 8.8%.

Table of Contents

The Non-Utility Power Generation Industry

Our 12 power generation projects are non-utility electric generating facilities that operate in the U.S. electric power generation industry. The electric power industry is one of the largest industries in the United States, generating retail electricity sales of approximately $365 billion in 2008, based on information published by the Energy Information Administration. A growing portion of the power produced in the United States is generated by non-utility generators. According to the Energy Information Administration, there were approximately 8,287 non-utility generators representing approximately 471 gigawatts of capacity in 2008, the most recent year for which data is available, (equal to 47% of total generating plants and 43% of nameplate capacity). Non-utility generators sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

Based on our experience in the acquisition market since our IPO, as well as transactions we are currently evaluating for potential investment, we believe that an active secondary market in the power generation sector will continue to provide us with meaningful acquisition and growth opportunities.

Table of Contents

OUR POWER PROJECTS

The following table summarizes key features of each of our operating projects. The projects are typically owned by holding companies, which hold limited partnership, general partnership or other equity interests. Our interests in each of the projects are held, directly or indirectly, through these holding companies.

A corporate organizational chart, which includes all our operating and development projects, is included on the following page.

Project Name	Location (State)	Type	Total MW	Economic Interest[1]	Accounting Treatment[2]	Net MW[3]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	E	89[4]	ACE	2024	BBB
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via CAISO[5]	N/A[6]	BBB+ to A[7]
Orlando	Florida	Natural Gas	129	50.00%	E	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013[8]	A[9]
Selkirk	New York	Natural Gas	345	17.70%[10]	E	14	Merchant	N/A	N/R
						47	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	E	59	Fortis Energy Marketing and Trading	2013	A-
						9	Sherwin Alumina	2020	NR
Topsham[11]	Maine	Hydro	14	50.00%	E	7	Central Maine Power	2011	BBB+

Badger Creek	California	Natural Gas	46	50.00%	E	23	Pacific Gas & Electric	2011	BBB+
Rumford	Maine	Coal/Biomass	85	26.40%	E	22	Rumford Paper Co.	2010	N/R
Koma Kulshan	Washington	Hydro	13	49.80%	E	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	PNM	2020	BB-

(1) Except as otherwise noted, economic interest represents the percentage ownership interest in the project held indirectly by Atlantic Power.

(2) Accounting Treatment: C Consolidated; and E Equity Method of Accounting (for additional details, see Note 2 of the consolidated financial statements for the year ended December 31, 2009).

(3) Represents our interest in each project's electric generation capacity based on our economic interest.

(4) Includes separate power sales agreement in which the project and ACE share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(5) California utilities pay TACs to CAISO, who then pays owners of TSRs, such as Path 15, in accordance with its FERC approved annual revenue requirement.

(6) Path 15 is a FERC regulated asset with a FERC-approved regulatory life of 30 years: through 2034.

(7) Largest payers of fees supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per CAISO imposed schedule.

(8) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.

(9) Fitch rating on Reedy Creek Improvement District bonds.

(10) Represents our residual interest in the project after all priority distributions are paid, which is estimated to occur in 2012.

(11) We own our interest in this project as a lessor.

Table of Contents

The following corporate organization chart includes all of our operating and development projects:

Table of Contents

Our projects are organized into the following six business segments:

Auburndale	Chambers
Lake	Path 15
Pasco	Other Project Assets

Auburndale Segment

General Description

The Auburndale Segment consists of a 155 MW dual-fired (natural gas and oil), combined-cycle, cogeneration plant located in Polk County, Florida, which commenced operations in July 1994. We own 100% of the Auburndale project, which is a "qualifying facility" (or "QF") under the rules promulgated by the Federal Energy Regulatory Commission (or "FERC"). We acquired Auburndale from ArcLight Energy Partners Fund I, L.P. and Calpine Corporation in a transaction that was completed on November 21, 2008.

Auburndale is located on an 11-acre site in the City of Auburndale, Florida. Capacity and energy from the project is sold to Progress Energy Florida (or "PEF") under three PPAs expiring at the end of 2013. Auburndale typically operates as a mid-merit generator, which means that it is called upon by PEF to run during periods of peak electricity demand on most weekdays and occasionally during periods of lower electricity demand. Steam is supplied to Florida Distillers Company and Cutrale Citrus Juices USA, Inc. The Florida Distillers steam agreement is renewed annually, and the Cutrale Citrus Juices steam agreement expires in 2013.

Auburndale has non-recourse debt outstanding of $29.0 million as of March 31, 2010 which fully amortizes over the term of its PPAs expiring in 2013. See "Project-Level Debt" on page 69 of this registration statement for additional details. Atlantic Power Corporation has provided letters of credit in the total amount of $13.4 million to support certain Auburndale obligations: $5.5 million to support its debt service reserve, $4.4 million to support its PPA, and $3.5 million to support its fuel supply agreement.

Power Purchase Agreement

Auburndale sells electricity to PEF under three PPAs each expiring on December 31, 2013. Under the largest of the PPAs, Auburndale sells 114 MW of capacity and energy. An additional 17 MW of committed capacity is sold under two identical 8.5 MW agreements with PEF. Revenue from the sale of electricity under the three PPAs consists of capacity payments based on a fixed schedule of prices, and energy payments. Capacity payments under the largest PPA are dependent on the plant maintaining a minimum on-peak capacity factor of 92 percent on a rolling twelve-month average basis. On-peak capacity factor refers to the ratio of actual electricity generated during periods of peak demand to the capacity rating of the plant during such periods. The project has achieved the minimum on-peak capacity factor continuously since commercial operation. Capacity payments under the smaller two agreements are dependent on the project maintaining a minimum on-peak capacity factor of 70 percent. Energy payments under the largest PPA are comprised of a fuel component based on the delivered cost of coal at two PEF-owned coal-fired generating stations and a component intended to recover operating and maintenance costs. Energy payments under the smaller two agreements are based on the lesser of PEF's actual avoided energy cost or an energy price index based on the delivered fuel cost at a specific coal-fired power plant owned by PEF.

Steam Sales Agreement

Auburndale provides steam to Florida Distillers Company and Cutrale Citrus Juices USA, Inc. under two separate steam purchase agreements. The Florida Distillers agreement automatically extends

Table of Contents

on an annual basis, and can be terminated by either party with 90 days notice. The Cutrale Citrus Juices agreement terminates on December 31, 2013 and contains automatic two-year renewal terms.

Fuel Supply Arrangements

Auburndale receives the majority of its required natural gas through a gas supply agreement with El Paso Merchant Energy, L.P. that expires on June 30, 2012. Under the agreement, El Paso provides a fixed amount of gas on a daily basis. The gas price is based on a fixed schedule of prices that escalate annually and is below current market prices. At historic utilization rates, the gas supplied under the El Paso contract has accounted for approximately 80% of the gas required by the project under its PPA commitments and the remaining required fuel is purchased at spot prices.

The required natural gas for the project is delivered through firm gas transportation agreements with Central Florida Gas Company and Florida Gas Transmission Company ("FGT") and is transported through the gas distribution system owned by Peoples Gas Transmission, Inc. ("Peoples"). The gas transportation agreements are co-terminus with the PPAs, expiring on December 31, 2013.

Operations & Maintenance

The Auburndale project is operated and maintained by an affiliate of Caithness Energy, LLC. In 2006, Auburndale entered into a maintenance agreement with Siemens Energy, Inc. for the long-term supply of certain parts, repair services and outage services related to the gas turbine. The term of the maintenance agreement is dependent on the number of maintenance inspections and is expected to expire in late 2012.

Auburndale entered into an agreement with TECO to transmit electric energy from the project to PEF. The agreement expires in 2024, unless extended as provided for in the agreement. Auburndale's cost for these services is based on a contractual formula derived from TECO's cost of providing such services.

Factors Influencing Project Results

Auburndale derives a significant portion of its revenue through capacity payments received under the PPAs with PEF. In the event the project's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward. Since it began commercial operation, the project has received full capacity payments.

During the term of the gas supply agreement, approximately 80% of the natural gas required to fulfill the project's PPAs is purchased at fixed prices. The remainder of the natural gas is purchased on the spot market. As a result, the project's operating margin is exposed to changes in market natural gas prices because the PPA does not effectively pass through those price changes to PEF. In order to mitigate this risk, Auburndale has entered into a series of financial swaps that effectively fix the price of natural gas to be purchased.

Table of Contents

The following table summarizes the hedge position related to natural gas requirements to satisfy Auburndale's PPAs as of June 16, 2010:

	2010	2011	2012	2013
Amount of gas volumes currently hedged:				
Contracted at fixed prices	80%	80%	40%	0%
Financially hedged with swaps	15%	13%	32%	79%
Total	95%	93%	72%	79%
Average price of financially hedged volumes (per million British thermal units, or "Mmbtu")(US$)	$6.30	$6.68	$6.51	$6.92

We will continue to periodically analyze whether to execute further hedge transactions intended to mitigate natural gas price exposure at Auburndale through the expiration of the PPAs with PEF.

The energy portion of Auburndale's revenue under the largest PPA with PEF is impacted by changes in the price of coal purchased by two power plants in Florida owned by PEF. Because these power plants purchase a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants is not directly correlated with changes in spot coal prices. Accordingly, changes in the price of coal procured by these two power plants will impact Auburndale's energy revenue.

Lake Segment

General Description

The Lake Segment consists of a 121 MW dual-fuel, combined-cycle QF cogeneration plant located in Florida, which began commercial operation in July 1993. We own 100% of the Lake project. In late 2007, the existing combustion turbines at the facility were upgraded to increase their efficiency by approximately 4% and output from 110 MW to 121 MW.

The Lake project is located on a 16-acre site at a citrus processing facility in Umatilla, Florida. Lake sells all of its capacity and electric energy to PEF under the terms of a PPA expiring in July 2013. The project is operated as a mid-merit facility typically running during 11 peak hours daily. Steam is sold to Citrus World, Inc. for use at its citrus processing facility and is also used to make distilled water in distillation units.

The Lake project does not have any debt outstanding. Atlantic Power Corporation has provided a $4.3 million letter of credit in favor of PEF to support the Lake project's obligations under its PPA.

Power Purchase Agreement

Electricity is sold to PEF pursuant to a PPA that expires on July 1, 2013. Revenues from the sale of electricity consist of a fixed capacity payment and an energy payment. Capacity payments are subject to the project maintaining a capacity factor of at least 90% during on-peak hours (11 hours daily), on a 12-month rolling average basis. Lake is subject to reductions in its capacity payment should it not achieve the 90% on-peak capacity factor. The project generally has achieved the minimum on-peak capacity factor continuously since commercial operation. Energy payments are comprised of a fuel component based on the cost of coal consumed at two PEF-owned coal-fired generating stations, a component intended to recover operations and maintenance costs, a voltage adjustment and an hourly performance adjustment. During off-peak hours, energy payments are made in accordance with a prescribed formula based on the price of natural gas, although Lake usually does not operate during off-peak hours.

Table of Contents

Steam Sales Agreement

The Lake project provides steam to Citrus World under a steam purchase agreement that expires in 2013. The project also supplies steam to an affiliate that uses steam to make distilled water, which is sold to unaffiliated third parties.

Fuel Supply Arrangements

The natural gas requirements for the facility are provided by Iberdrola Renewables, Inc. and TECO Gas Services, Inc. ("TGS"). Both the Iberdrola and TGS agreements contain market index based prices, commenced on July 1, 2009 and expire on July 31, 2013.

Natural gas is transported to the project from supply points in Texas, Louisiana and Mississippi to Florida under contracts with Peoples Gas System.

Operations & Maintenance

The Lake project is operated and maintained by an affiliate of Caithness Energy, LLC.

Lake also has a contractual services agreement and a lease engine agreement in place with General Electric (or "GE"). The contractual services agreement provides for planned and unplanned maintenance on the two gas turbines at the plant. The lease engine agreement provides temporary replacement gas turbines to Lake to support operations when the Lake turbines require significant maintenance.

Factors Influencing Project Results

The Lake project derives a significant portion of its operating margin through capacity revenues received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward, although the project rarely experiences such reductions. During the term of the current gas supply agreement, effective July 1, 2009, Lake's operating margins are exposed to changes in natural gas prices through the end of the PEF PPA in 2013. As a result, we have entered into a series of financial swaps that effectively fix the price of natural gas supplied to Lake thereby reducing fuel price risk.

The following table summarizes the volumes hedged relative to natural gas requirements under Lake's PPA as of June 16, 2010:

	2010	2011	2012	2013
Amount of gas volumes currently hedged:				
Contracted at fixed prices	0%	0%	0%	0%
Financially hedged with swaps	80%	78%	90%	65%
Total	80%	78%	90%	65%
Average price of financially hedged volumes (per "Mmbtu")(US$)	$7.11	$6.52	$6.90	$7.05

We will continue to analyze whether to execute further hedge transactions to mitigate natural gas price exposure at Lake through expiration of the PPA with PEF.

The energy portion of Lake's revenue under the PPA with PEF is impacted by changes in the price of coal used by two of their power plants in Florida. Because these power plants secure a significant portion of their coal through contracts of varying lengths, the price of coal burned at those plants does not move in tandem with changes in spot coal prices.

Table of Contents

The energy payment under the PPA includes a performance adjustment. For energy deliveries in excess of contracted capacity to PEF during on-peak periods in which the system price for energy exceeds the PPA energy rate, the project receives the then as-available energy rate, determined according to regulatory methodology. Conversely, when the project is not available and is dispatched by PEF, the project incurs negative performance adjustment charges corresponding to the difference between the then as-available energy rate and the PPA energy rate.

Pasco Segment

General Description

The Pasco Segment consists of the 100% owned Pasco project, a 121 MW dual fuel, combined-cycle, cogeneration plant located in Dade City, Florida, which began commercial operations in 1993 as a QF. With the expiration of the original PPA with PEF in 2008, and the commencement of the tolling agreement with TECO in 2009, Pasco self-certified with the FERC as an exempt wholesale generator and was no longer required to maintain QF status. The project owns the 2.7 acre site approximately 45 miles north of Tampa, Florida.

Power Purchase Agreement

Electricity is sold to TECO pursuant to a tolling agreement that commenced on January 1, 2009 and expires on December 31, 2018. Under the tolling agreement, TECO purchases the project's capacity and conversion services. Pasco converts fuel supplied by a TECO affiliate into electricity. Revenues consist of capacity payments, start-up charges, variable payments based on the amount of electricity generated and heat rate bonus payments based on the actual efficiency of the plant versus the contract efficiency. Atlantic Power Corporation has provided a $10 million letter of credit in favor of TECO to support the project's obligations under the tolling agreement.

In exchange for obtaining the right to sell any potential excess emissions allowances from the plant, TECO accepted financial responsibility for any costs associated with additional allowances required and changes to environmental laws, including state or federal carbon legislation.

Fuel Supply Arrangements

Under the terms of the tolling agreement, TECO is responsible for the fuel supply and is financially responsible for fuel transportation to the project.

Operations & Maintenance

The Pasco project is operated and maintained by an affiliate of Caithness Energy, LLC.

Pasco also has a services agreement and a lease engine agreement in place with GE. The services agreement provides for discounts for planned and unplanned maintenance on the project's two natural gas turbines, and commits the project to use GE for gas turbine maintenance activities. Under the lease engine agreement, GE rapidly provides temporary replacement natural gas turbines to the project to support operations when the project's turbines are removed from the site for significant maintenance.

Factors Influencing Project Results

The Pasco project derives the majority of its revenues under the tolling agreement with TECO through capacity payments. In the event the project does not maintain certain levels of availability, the capacity payments will be reduced. Based on historical performance, we expect the project to continue to exceed the availability requirement of 93% in the summer and 90% in the winter. A portion of the project's operating margin is based on three variable payments from TECO, consisting of a variable operation and maintenance charge, a start charge and a heat rate bonus. As a result, the project

Table of Contents

achieves a variable margin during periods of operation; and as a result, the level of variable margin is impacted by how often the plant is called on to produce electricity.

Chambers Segment

General Description

The Chambers Segment consists of our 40% equity investment in the Chambers project, a 262 MW pulverized coal-fired cogeneration facility located at the E.I. du Pont de Nemours and Company Chambers Works chemical complex near Carney's Point, New Jersey, which began commercial operation in March 1994 as a QF. Affiliates of Goldman Sachs and Energy Investors Funds, an established private equity fund manager that invests in the U.S. energy and electric power sector, in the aggregate hold 60% of the general partner interests. Chambers sells electricity to Atlantic City Electric ("ACE") under two separate power purchase agreements, a "Base PPA" and a power sales agreement. Historically, the project has operated as a baseload plant, however, during periods of low energy market pricing, the facility has run at partial or minimum load. Steam and electricity are sold to DuPont pursuant to an energy services agreement. The project site is leased from DuPont. Under the terms of the ground lease, DuPont has a right to purchase the project within 60 days of the lease expiration in 2024, or upon earlier termination of the lease, at fair market value.

Chambers financed the construction of the project with a combination of term debt due March 31, 2014 and New Jersey Economic Development Authority bonds due July 1, 2021. The term loan is expected to amortize over its remaining term, while the bonds are repayable at maturity. Both are non-recourse to Atlantic Power Corporation. Our 40% share of the total debt outstanding at the Chambers project as of March 31, 2010 is $83.3 million. See "Project-Level Debt" on page 69 of this registration statement for additional details.

Epsilon Power Partners, L.P., our wholly-owned subsidiary, directly owns our interest in Chambers. Epsilon has outstanding debt of $37.2 million as of March 31, 2010 which fully amortizes by its final maturity in 2019 and is non-recourse to Atlantic Power Corporation. See "Project-Level Debt" on page 69 of this registration statement for additional details.

Power Purchase Agreements

Base PPA

The 30-year term of the Base PPA with ACE expires in 2024. ACE has agreed to purchase 184 MW of capacity and has dispatch rights for energy of up to 187.6 MW during the summer season (May 1 to October 31) and 173.2 MW during the winter season (November 1 to April 30). The project must be available to deliver power to ACE at 90% of the average availability rate of a specific group of mid-Atlantic generating stations. Capacity prices are determined using a fixed price with a capacity factor adjustment. The energy payment under the Base PPA is divided between on-peak and off-peak periods and linked to a coal index that is identical to the project's coal supply contract escalation provisions. Chambers is guaranteed a minimum energy payment equivalent to 3,500 hours of operation per contract year, whether or not it is run that way, provided the project is available for energy production for at least 3,500 hours during the course of the contract year.

DuPont Energy Services Agreement

DuPont purchases all its electrical needs for its Chambers Works chemical complex from the Chambers project, subject to a peak requirement of 40 MW, under the energy services agreement. The initial term of the agreement expires in 2024 but will continue thereafter unless terminated by at least 36 months prior written notice. The electricity sold under the agreement contains a fixed price, which is adjusted quarterly by the lesser of either: (i) the price of coal delivered to the facility; and (ii) the change in ACE's average retail rate.

Table of Contents

In December 2008, Chambers filed suit against DuPont for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In the event the dispute cannot be resolved through settlement, a trial is expected in the second half of 2010. We do not believe that the outcome of this litigation will have a material impact on Atlantic Power Corporation.

Power Sales Agreement

Energy generated at the Chambers project in excess of amounts delivered to ACE under the Base PPA and to DuPont is sold to ACE under a separate power sales agreement. Under this agreement, energy that ACE does not find economically attractive at the Base PPA's energy rate, but which may be cost effective to sell into the spot market ("Undispatched Energy"), may be self-scheduled by the project to capture additional profits. Margins on Undispatched Energy sales are shared between ACE (40%) and the project (60%). Energy not committed to ACE under the Base PPA and not called upon by DuPont under the energy services agreement may also be sold into the market under a similar margin sharing arrangement with ACE (30% to ACE and 70% to Chambers). The agreement also provides for the sale by Chambers into the market of capacity not contracted under the Base PPA pursuant to the same margin sharing arrangement with ACE (30% to ACE and 70% to Chambers).

The power sales agreement expires in July 2010 and has historically been extended at each previous contract expiration date.

Steam Sales Agreement

Some of the steam generated at the Chambers project is sold to DuPont under the energy services agreement, which expires in 2024, but will continue in effect thereafter unless terminated by either party on at least 36 months prior notice. The agreement requires steam to be provided to DuPont up to the peak steam requirement levels that vary throughout the year. DuPont may purchase steam in excess of the peak steam requirement from any third party, subject to Chambers' right of first refusal to provide steam at the same price. Subject to certain conditions, DuPont has the option to construct and operate its own steam generation facility after 2014. DuPont is required to purchase a minimum quantity of steam necessary for the project to maintain its status as a QF. The steam price is subject to quarterly adjustments based on the price of coal delivered to the project. DuPont has the option in certain circumstances to take over operation of the steam facility in the event of prolonged failure to deliver steam.

Fuel Supply Arrangements

Coal is supplied to the Chambers project pursuant to a coal purchase agreement with Consol Energy Inc., which expires in 2014 and is subject to a five to ten-year renewal based on good faith negotiations. The agreement governs the sale of coal (including transportation) to the project and the disposal of related ash. Consol is obligated to supply the entire coal requirements for the project, which may include stockpiling. The price escalator under the Base PPA with ACE uses the same index as the coal supply agreement (average coal cost of 25 mid-Atlantic region coal power plants), effectively passing through changes in coal prices to ACE.

Operations & Maintenance

Operations and maintenance of the Chambers project is performed pursuant to an agreement with Cogentrix Energy, Inc., which expires in April 2014. Thereafter, the agreement will be automatically renewed for periods of five years until terminated by either party on six months notice. Cogentrix is paid a base annual fee in addition to cost reimbursement. Cogentrix is also eligible for performance

Table of Contents

fees based on facility net availability, efficiency and excess energy optimization, and is eligible for an additional management performance bonus.

Regional Greenhouse Gas Initiative

With New Jersey's implementation of the Regional Greenhouse Gas Initiative ("RGGI") on January 1, 2009, the Chambers project was required to obtain carbon dioxide ("CO_2") allowances in an amount corresponding to the CO_2 emissions of the facility. Previously in 2008, the State of New Jersey passed legislation that provided for the sale of CO_2 allowances at the price of $2.00 per allowance to certain generating facilities which were certified by the New Jersey Department of Environmental Protection ("NJDEP"). Chambers received this certification from the NJDEP in late 2009. Earlier in 2009, the project purchased approximately 480,000 allowances through the quarterly RGGI auctions and broker purchases. In December 2009, Chambers purchased 2.1 million allowances from the NJDEP at the price of $2 per allowance. A portion of the NJDEP purchase, in combination with the previously purchased allowances, satisfies the project's RGGI compliance requirements for 2009. The remainder of the 2009 NJDEP allowance purchase will be used to meet the 2010 requirements along with 2010 NJDEP allowance purchases.

Factors Influencing Project Results

The Chambers project derives a significant portion of its operating margin through capacity revenues received under the Base PPA. In the event the facility does not maintain a minimum level of availability under the Base PPA, the project's capacity payments from ACE would be reduced, although it has never experienced such a reduction. Energy sales under the Base PPA are expected to generate positive margins due to the effective hedging of energy prices and coal costs through the use of identical indexing in the energy payment under the Base PPA and the coal prices under the contract supply contract. While the indexing is identical, adjustments to the energy price under the Base PPA occur annually, whereas coal price adjustments occur quarterly.

During periods of low spot market electricity prices, energy sales margins may be negatively impacted due to the pricing structure under the Base PPA and power sales agreement. ACE will reduce purchases under the Base PPA to the minimum requirement when the spot electricity price is below the price under the Base PPA. When spot market prices drop below the Base PPA price, but exceed the project's variable production cost, ACE pays for energy based on the power sales agreement, under which a portion of the margin above the project's production cost is shared with ACE. In the unusual situation when the spot electricity price is in excess of the Base PPA but less than the project's variable production cost (which may occur during off-peak periods), Chambers is required to sell energy to ACE at below its production cost. In some cases, the project is further negatively impacted by the facility's reduced fuel efficiency while operating at partial load to minimize operating at a negative margin.

The debt at our wholly-owned Epsilon holding company includes restrictions on the upstream distribution of our share of partner distributions from Chambers. Cash flow from Chambers may be held in a reserve account by Epsilon's lender to the extent certain debt service coverage ratios are not achieved. Upon meeting the coverage ratio requirements, funds are distributed to us.

Path 15 Segment

General Description

The Path 15 Segment consists of our ownership of 72% of the transmission system rights ("TSRs") in the Path 15 project, an 84-mile, 500-kilovolt transmission line built along an existing transmission corridor in central California. The Path 15 project commenced commercial operations in 2004. The Path 15 project facilitates the movement of power from the Pacific Northwest to southern California in

Table of Contents

the summer months and from generators in southern California to northern California in the winter months. The TSRs entitle us to receive an annual revenue requirement that is regulated by the FERC The annual revenue requirement is collected from California utilities and remitted to owners of TSRs by the California Independent System Operator ("CAISO").

The Path 15 project and right of way is owned and operated by the Western Area Power Administration, a U.S. Federal power agency that operates and maintains approximately 17,000 miles of transmission lines. The operation of the Path 15 project consists entirely of the transmission of electric power, which is not subject to the same operating risks of a power plant or the volatility that may arise from changes in the price of electricity or fuel.

The CAISO is a not-for-profit corporation that acts as a clearinghouse to settle third-party transactions involving the purchase and sale of power in California. Owners of transmission assets must place their assets under the operational control of the CAISO by entering into a standard transmission control agreement with them. In general, the CAISO coordinates the dispatch of power generation and manages the reliability of, and provides open access to, the transmission grid.

Three of our wholly-owned subsidiaries have incurred non-recourse debt relating to our interest in the Path 15 project. Total debt outstanding at the Path 15 project as of March 31, 2010 is $161.3 million, which fully amortizes over their remaining term ending 2028. See "Project-Level Debt" on page 69 of this registration statement for additional details. We have provided letters of credit totaling $8.4 million to support these debt service obligations.

Annual Revenue Requirement FERC Rate Case

The revenue collected by Path 15 is regulated by the FERC on a cost-of-service rate base methodology. Path 15 files a rate case with the FERC every three years to establish its revenue requirement for the next three year period. The revenue requirement includes all prudently incurred operating costs, depreciation and amortization, taxes, and a return on capital.

In December 2007, we filed a rate application with the FERC to establish Path 15's revenue requirement through 2010. In January 2008, several parties filed protests and interventions to become parties to the proceeding. In February 2008, the FERC issued an order summarily approving the requested return on equity and, allowing the requested rates to go into effect as of February 20, 2008, subject to refund. California Public Utilities Commission and Southern California Edison filed requests for rehearing of that order. In February 2009, we filed an unopposed motion requesting suspension of the trial schedule to allow the parties to the rate case to finalize a settlement. In March 2009, we filed a settlement offer with the FERC. The settlement was supported by all parties to the proceeding. In August 2009, the FERC issued an order approving the settlement offer. We believe that the settlement was reasonable and has not significantly impacted the expected cash flow from the project. On October 30, 2009, the Path 15 project issued refunds reflecting the difference between the rates collected as of February 2008 pursuant to the December 2007 filing and the rates provided for under the settlement.

Factors Influencing Project Results

The primary factor influencing the Path 15 project results is its FERC-regulated revenue requirement. Under the FERC's cost of service methodology, all prudently incurred expenses are permitted to be recovered in the revenue requirement including costs of the rate case itself every three years. Cash distributions to us could be adversely impacted by factors such as which year is used to establish the revenue requirement for the next three years and whether the FERC approves a return on equity less than 13.5% in future rate cases.

Table of Contents

Other Project Assets

Orlando Project

General Description

The Orlando project, a 129 MW natural gas-fired combined-cycle cogeneration facility located in an industrial park near Orlando in Orange County, Florida, commenced commercial operation in 1993 as a QF. We own a 50% interest in the project and Northern Star Generation, LLC owns the remaining 50% interest. The project is situated on a four acre site located adjacent to an air separation facility owned by Air Products and Chemicals, Inc., which serves as the project's steam customer. Orlando sells all of its electricity to PEF and Reedy Creek Improvement District under long-term PPAs, and also sells chilled water produced using steam from the project to Air Products and Chemicals. The Orlando project typically operates as a baseload plant. Both we and Northern Star have provided letters of credit in the amount of $1.6 million each in support of the project's obligations under the PEF PPA.

Power Purchase Agreements

Progress Energy Florida

Orlando sells electrical capacity and energy to PEF under a PPA that expires on December 31, 2023. The project is obligated to sell and deliver a committed capacity of 79.2 MW and has committed to a 93% on-peak capacity factor. Orlando receives a monthly capacity payment based on achieving the on-peak capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to PEF. The capacity payment escalates at 5.1% annually and is reduced if the facility's on-peak capacity factor is below 93%, on a 12-month rolling average basis. Energy payments are comprised of a fuel component based on the cost of coal purchased at two PEF-owned coal-fired generating stations, an operations and maintenance component, a voltage adjustment and an hourly performance adjustment. Off-peak energy prices are based on the on-peak spot market energy price discounted by 10%.

On August 4, 2009, PEF provided notice to Orlando that the committed capacity under its PPA would be increased to 115 MW upon expiration of the Reedy Creek PPA in 2013, upon meeting certain conditions.

Reedy Creek Improvement District

Orlando sells electrical capacity and energy to the Reedy Creek Improvement District, a municipal district serving the Walt Disney World complex, under a PPA that expires in 2013. Orlando is obligated to sell and deliver 35 MW of electricity and has committed to a 93% average capacity factor. Orlando receives a monthly capacity payment based on the actual average capacity factor and a monthly energy payment based on the total amount of electric energy actually delivered to Reedy Creek. The PPA may be extended for an additional ten-year term upon the consent of both parties. The capacity payment is fixed at a rate that escalates at 4.5% annually and is based upon achieving a 93% average capacity factor, calculated on a three-year rolling average basis. The agreement provides both incentive and penalty provisions for performance above and below a 93% average capacity factor, respectively. Reedy Creek also reimburses Orlando for a portion of the reservation charges associated with the project's firm gas transportation agreement with Florida Gas. In 2005, Orlando executed an agreement with Reedy Creek for periodic sales of up to 15 MW of non-firm available energy at firm rates.

Excess Energy Sales

In 2006, Orlando executed a master purchase and sale agreement with Rainbow Energy Marketing Corporation. Under the agreement, Rainbow markets up to 15 MW of non-firm energy at spot market

Table of Contents

rates subject to the profitability of such sales. The arrangements with Rainbow can be terminated by either party upon 30 days notice.

Steam Sales Agreement

Orlando entered into an agreement with a subsidiary of Air Products and Chemicals, Inc. to supply chilled water produced using steam from the project to its cryogenic air separation facility. Orlando does not have any minimum steam delivery requirements beyond the thermal and efficiency requirements required to maintain its QF status. Orlando is required to purchase its nitrogen requirements from Air Products and Chemicals, but does not have a minimum purchase requirement. Both the purchase price of nitrogen and the sales price of chilled water are at fixed prices that adjust based on the percentage increase/decrease in the producer price index.

Because of reduced demand for chilled water at Air Products and Chemicals during certain periods, and to ensure continued compliance with QF requirements, Orlando procured and installed water distiller units in 2009, and entered into contracts to provide the distilled water to unaffiliated third parties in the local area.

Fuel Supply Arrangements

Orlando buys natural gas from Orlando Power Holdings, LLC, which is indirectly owned by Northern Star, under an agreement expiring on December 31, 2013. Orlando Power has a back-to-back agreement for the purchase and supply of natural gas from Vastar Gas Marketing, Inc., which is a wholly-owned subsidiary of BP Energy Company. Under the agreement, which expires on December 31, 2013, Vastar is obligated to provide Orlando Power with its entire daily natural gas requirement. Orlando's purchase price is tied to the same coal-based and fixed escalators used for calculating the energy payments under the PPAs. Orlando also has a gas supply agreement with TECO Gas, but is not currently purchasing any natural gas under this agreement.

Orlando has two gas transportation agreements expiring on July 31, 2010 with Peoples Gas for the delivery of natural gas to the project. We expect that those will be renewed as they are simply based on published tariff rates. Peoples Gas has entered into co-terminus back-to-back agreements with Florida Gas for the delivery of natural gas to the project. Orlando has a contractual right to extend these agreements. Transportation costs under the agreements are determined by Florida Gas' rate schedule as filed with the FERC. These agreements provide for the transportation of up to 23,600 Mmbtu (million British thermal units) per day to the project.

Operations & Maintenance

The Orlando project is operated and maintained by an affiliate of Northern Star under an operations and administrative services agreement expiring on December 31, 2023. The operator is compensated on a cost-reimbursement basis plus a fixed general and administrative charge. In addition, the operator is entitled to receive an incentive fee equal to a percentage of the excess of Orlando's operating cash flow after deducting originally anticipated maintenance capital and anticipated debt service. In 1997, Orlando also entered into a maintenance agreement with Alstom Power Inc. for the long-term supply of hot gas path gas turbine parts, under which Alstom receives a monthly fee from the partnership and additional fees in certain circumstances.

Factors Influencing Project Results

The Orlando project receives a significant portion of its revenues through capacity payments received under the PPA with PEF. In the event the facility's on-peak capacity factor falls below a specified level, capacity payments will be adjusted downward. The energy payment under the PEF PPA largely consists of an energy component, which is adjusted based on the same coal index as used in the gas supply pricing.

Table of Contents

The energy payment under the PPA with PEF includes a performance adjustment. During on-peak periods in which the market price for energy exceeds the PPA energy rate, for energy deliveries in excess of PEF scheduled capacity, the project receives the then as-available energy rate, determined according to regulatory methodology. Conversely, during on-peak periods when the project delivers less than the scheduled capacity, the project incurs negative performance adjustment charges corresponding to the difference between the then as-available energy rate and the PPA energy rate.

The Reedy Creek PPA also contains incentive and penalty provisions for performance above and below a specified capacity factor.

Selkirk Project

General Description

The Selkirk project is a 345 MW dual-fuel, combined-cycle cogeneration plant located in the Town of Bethlehem in Albany County, New York, and commenced commercial operation in 1994 as a QF. The project includes two units: Unit I (80 MW) sells electricity into the New York merchant market and Unit II (265 MW) sells electricity to Consolidated Edison, Inc. (or "Con Ed"). The Selkirk project is typically operated as a mid-merit plant. The other partners include affiliates of Cogentrix, Energy Investors Funds, The McNair Group, and Fort Point Power LLC (an affiliate of Osaka Gas Energy America Corporation). Each of the partners has an interest in cash distributions by the project which changes when certain partners achieve a specified return on their equity contributions as set forth in the partnership agreement. We own: (i) 13.62% interest in the priority distributions up to a fixed semi-annual amount as described below; (ii) 19.94% interest on any distributions in excess of the priority distributions; and (iii) 17.7% of all distributions made after the last priority distribution is made, estimated to occur in 2012. If priority distributions are not made at the maximum amount, the unpaid amounts accumulate and are paid when funds are available in subsequent periods. As of December 31, 2009, our 13.62% share of unpaid priority distributions was $0.5 million. In addition to this accumulated amount, our share of the maximum semi-annual priority distributions in 2010, 2011 and 2012 is approximately $1.2 million, $0.8 million and $0.7 million, respectively. The 15.7 acre project site is situated adjacent to a Saudi Arabia Basic Industries Corporation (or "SABIC") plastics manufacturing plant, which also purchases steam from the project. Selkirk leases the project site under a long-term lease from SABIC.

The Selkirk project has 8.98% first mortgage bonds outstanding. Our share of the outstanding amount of these bonds was $25.7 as of March 31, 2010, which fully amortizes over the remaining term ending in 2012. See "Project-Level Debt" on page 69 of this registration statement for additional details.

Power Purchase Agreements

Since the expiration of Selkirk's agreement to sell 80 MW of capacity and energy from Unit I to National Grid in July 2008, Selkirk has been selling energy from Unit 1 into the New York merchant market. 265 MW of capacity and energy from Unit II is sold to Con Ed under a PPA that expires on September 1, 2014, subject to a ten-year extension at the option of Con Ed under certain conditions. The Unit II PPA provides for a capacity payment, a fuel payment, an operations and maintenance payment and a payment for transmission from the project to Con Ed. The capacity payment, a portion of the fuel payment, a portion of the operations and maintenance payment and the transmission payment are fixed charges to be paid on the basis of plant availability.

Steam Sales Agreement

Selkirk sells steam generated at the project to the SABIC plastics manufacturing plant under an agreement that expires on September 1, 2014. Under the agreement, SABIC is not charged for steam in an amount up to the annual equivalent of 160,000 lbs/hr during each hour in which the SABIC plant

Table of Contents

is in production. SABIC pays the project a variable price for steam in excess of this amount. SABIC is required to purchase the minimum thermal output necessary for Selkirk to maintain its QF status.

Fuel Supply Arrangements

Selkirk buys natural gas for Unit I at spot market prices under a contract with Coral Energy Canada expiring on October 31, 2012. Selkirk has gas supply agreements for Unit II with Imperial Oil Resources Limited, EnCana Corporation and Canadian Forest Oil Ltd., which expire on October 31, 2014.

The project also has long-term contracts for the transportation of Units I and II natural gas volume on a firm 365-day per year basis in place with TransCanada Pipelines Limited, Iroquois Gas and Tennessee Gas. The Unit I and Unit II gas transportation contracts expire on November 1, 2012 and November 1, 2014, respectively.

Natural gas that is not used by Selkirk to generate power under its gas supply arrangements may be remarketed. Under certain market conditions, additional income is generated from such re-sales of natural gas. Units I and II have the capability to operate on fuel oil subject to certain limitations under the project's air permit and are able to switch fuel sources from natural gas to fuel oil and back without interrupting the generation of electricity.

Operations & Maintenance

GE operates the Selkirk project under an agreement expiring on December 31, 2012. The agreement provides for a fixed fee, capital parts discounts, a pass-through of management costs and a performance bonus. Management services for Selkirk are provided by Cogentrix under an administrative services agreement that expires in September 2014. Cogentrix is entitled to compensation under the agreement which is subject to renegotiation every four years and provides for the full recovery of its actual costs and properly allocated overhead plus a reasonable fee which must be approved by all of the Selkirk partners.

Regional Greenhouse Gas Initiative

In 2009, in order to comply with RGGI, the project commenced purchasing CO_2 allowances in the quarterly RGGI auctions. At year-end, the project had purchased adequate allowances to cover the amount needed for RGGI compliance in 2009, except for approximately 184,000 allowances. Under the RGGI rules, a compliance period consists of three years, during which time the emitter is required to obtain allowances corresponding to its CO_2 emissions during the same period. New York State allocates a limited number of free allowances to generators that have long-term contracts. A portion of the project's 2009 requirement will be met with these free allowances. The project expects to purchase additional allowances in 2010 in order to satisfy its 2009 requirement. In resolution of a lawsuit brought by an unaffiliated owner of another New York power plant in 2009 challenging New York's RGGI rules, a consent decree is being finalized under which ConEd will reimburse the Selkirk project for the cost of additional allowances needed in excess of the free allowances allocated by New York.

Factors Influencing Project Results

Energy produced by Unit I (80 MW) is sold at market prices based on the project's bid into the spot market. The project is therefore exposed to fluctuations in market energy prices which may impact Unit I energy sales margins. Under the PPA with Con Ed, the Project receives significant capacity revenues based on meeting availability requirements and also receives an energy payment whenever Con Ed calls on Unit II (265 MW) to generate electricity. The energy payment is primarily dependent on the fuel price component, indexed predominantly to natural gas prices, but also has a small component based on oil prices.

Table of Contents

In periods when Unit I or Unit II is not generating electricity, substantial volumes of natural gas are available to be re-sold. Depending on market prices when reselling compared to contract prices when the gas was nominated at the beginning of each month, the excess gas can be resold at significant positive margins or occasionally at a loss.

Gregory Project

General Description

The Gregory project is a 400 MW natural gas-fired combined cycle cogeneration QF located near Corpus Christi, Texas that commenced commercial operation in 2000. The Gregory project is owned by Gregory Power Partners, LP, a Texas limited partnership, and our ownership interest in Gregory Power is approximately 17%. The other owners are affiliates of JPMorgan Chase & Co. and John Hancock Life Insurance Company. Gregory currently sells approximately 345 MW of its capacity to Fortis Energy Marketing and Trading GP and sells up to 33 MW of electric energy and capacity to Sherwin Alumina Company, which is owned by Glencore International AG, with the remainder sold in the spot market. While not strictly a baseload facility, Gregory typically is operated at a high capacity factor. The project is located on a site adjacent to Sherwin Alumina's production facility, which also serves as the project's steam customer. Gregory leases the land on which the project is located from Sherwin under an operating lease which expires in August 2035.

The Gregory project was financed by ING Capital Corporation ("ING") and a consortium of other lenders. The loan matures in 2017 and is expected to be amortized over its remaining term. Our share of the total debt outstanding at the Gregory project as of March 31, 2010 was $15.6 million. See "Project-Level Debt" on page 69 of this registration statement for additional details.

In November 2008, Gregory's managing partner, discovered that the state authorization of the project's Prevention of Significant Deterioration Air Permit had lapsed due to a discrepancy in the representation of the renewal date of the state authorization by a consultant in 2002. The issue was self-reported to the Texas Commission of Environmental Quality (or "TCEQ"). During the first quarter of 2009, Gregory submitted its initial draft permit application to the TCEQ, which deemed it administratively complete, and completed the technical aspects of the permitting process. In December 2009, the TCEQ provided Gregory Power a draft of a new permit, and on March 15, 2010, the TCEQ issued the new permit. We believe the new permit limits are achievable by the project and will not require the installation of additional emissions control equipment.

Power Purchase Agreements

Gregory sells 345 MW of its output to Fortis under a PPA that began on January 1, 2009 and expires December 31, 2013. Under the terms of the Fortis agreement, Fortis pays a fixed capacity payment and an energy payment that is based on the price of natural gas at Houston Ship Channel and a contract heat rate. (Heat rate refers to the amount of natural gas that is required to generate one MW of electricity.) Energy sales to Fortis consist of two tranches; a 234 MW "must-run" block and a 111 MW "dispatchable" block. The must-run block corresponds to the project's minimum energy output while satisfying Sherwin's electricity and steam requirements without the use of Gregory's auxiliary boilers. The dispatchable block is the portion of Gregory's output that can be scheduled at the option of Fortis as either energy, ancillary services or balancing energy. Credit support for the PPA consists of a $10 million letter of credit issued by ING which is backed by letters of credit from the project's partners, including a $1.7 million letter of credit provided by Atlantic Power Corporation.

Steam Sales Agreement

Gregory sells steam to Sherwin under an agreement that expires in 2020. Under the terms of the agreement, Gregory is the exclusive source of steam to Sherwin's alumina plant, up to a maximum of 1,500,000 lbs/hr.

Table of Contents

Fuel Supply Arrangements

Gregory purchases natural gas under various short-term and long-term agreements. Gregory has the option of procuring 100% of its natural gas requirements from Kinder Morgan Tejas Pipeline, L.P., under a market-based gas supply agreement that expires in August 2010. Gregory Power has begun discussions with several gas suppliers for replacement supply when this contract expires.

In March and June 2008, the project entered into pay fixed, receive floating, natural gas swap agreements with Sempra Energy Trading Corp. for the period January 2009 through December 2010. While Gregory has structured its power and steam sales agreements to mitigate the price risk between its fuel supply and electricity sales agreements, the project has some residual exposure to natural gas price risk due to the difference between the project's actual heat rate and the contractual heat rate under the Fortis PPA. The swap agreements partially mitigate this natural gas price risk.

Operations & Maintenance

Babcock and Wilcox Power Generation Group, Inc. ("Babcock and Wilcox") is responsible for the operation and maintenance of the Gregory project under an agreement that terminates in July 2010. The project is evaluating whether to renew the contract with Babcock and Wilcox or contract with another nationally-recognized operations and maintenance provider. The operator receives a fee for management of the facility (subject to escalation) on a quarterly basis and reimbursement of certain costs.

Energy Management Services

Gregory has entered into a contract with Tenaska Power Services, Co. to provide energy management services such as marketing excess power from the Project through the end of 2011. Tenaska will optimize Gregory's assets in the ancillary services market of the Electric Reliability Council of Texas, purchase natural gas for operations, provide scheduling services, provide back-office support and serve as Gregory's retail energy provider and qualified scheduling entity.

Factors Influencing Project Results

The Gregory project derives a significant portion of its operating margin through energy revenues under its PPA with Fortis. Energy revenues are dependent on the price of natural gas at Houston Ship Channel and a contract heat rate. The project achieves a margin on its energy revenue due to the facility's actual heat rate being lower than the contract heat.

Gregory also receives a capacity payment under the Fortis PPA which is dependent on maintaining certain minimum performance requirements. The project's capacity payments are subject to reduction if it fails to meet these requirements. Due to a forced outage in 2009, the project only received 98% of the full capacity revenue. However, historically the project has met all of the performance standards under the Fortis PPA.

Topsham Project

General Description

The Topsham project is a 14 MW hydroelectric facility located on the Androscoggin River at the Pejepscot dam near Topsham, Maine and began commercial operation in 1987 as a QF. A 100% undivided interest in the Topsham project and a 100% undivided interest in the Topsham project site are owned by a financial institution, in its capacity as owner trustee for the benefit of Atlantic Power Corporation (50%) and DaimlerChrysler Services North America LLC (50%) as owner participants. Electricity is sold to the Central Maine Power Company (or "CMP") under a PPA that expires in 2011.

The Topsham project is leased and operated by Topsham Hydro Partners Limited Partnership ("THP"), a Minnesota limited partnership. Pursuant to a sale and lease back transaction, THP leases

Table of Contents

both our interests in the project and in the project site until November 17, 2011. At the end of the lease term, THP has the option to renew the lease or acquire our share of the project and the project site. Lease payments made by THP are based on project's operating cash flows.

Power Purchase Agreement

Electrical output from the Topsham project is sold to CMP under a PPA that contains a fixed price schedule and terminates on December 31, 2011.

Operations & Maintenance

THP operates the project and provides all general and administrative services for the project under an agreement in effect until the earlier of December 31, 2027 or upon THP becoming the owner of 100% of the project and the project site.

Badger Creek Project

General Description

The Badger Creek project is a 46 MW simple-cycle, cogeneration facility located near Bakersfield, California which began commercial operation in 1991 as a QF. The Badger Creek project is owned by Badger Creek Limited, L.P. ("Badger"), a Texas limited partnership in which we own a 50% partnership interest. Juniper Generation, LLC, which is indirectly owned by affiliates of ArcLight Capital Partners, LLC, owns the other 50% partnership interest. Electricity is sold to Pacific Gas & Electric Corporation ("PG&E") under a PPA expiring in 2011. The project typically operates in a baseload configuration. Steam is sold to OXY USA Inc., an affiliate of Occidental Petroleum Corporation, under an agreement that expires in 2011. Badger leases the approximately 3.5 acre site for the Badger Creek project under a ground lease. The term of the lease expires in July 2021 and the parties may extend for up to 10 additional one-year periods.

Power Purchase Agreement

Electricity generated by the Badger Creek project is purchased by PG&E under a PPA that expires in 2011. The PPA provides for monthly capacity and energy payments, and Badger is entitled to receive a performance bonus if the average on-peak capacity factor exceeds 85%. The energy price received under the PPA is linked to PG&E's interim "short-run avoided cost," as discussed below.

Steam Sales Agreement

Steam from the Badger Creek project is sold to OXY under an agreement which expires in 2011. The agreement provides for successive renewal terms of one year unless either party gives advance notice of termination. OXY utilizes the steam in its enhanced oil recovery operations to allow for more effective and efficient extraction of heavy crude oil. Subject to certain conditions, OXY has an obligation to buy steam under this agreement in an amount not less than the minimum requirements necessary to maintain the project's status as a QF. Although OXY is not currently purchasing any power from the project, the steam agreement allows for up to 1 MW of electricity to be sold to OXY.

Fuel Supply Arrangements

The Badger Creek Project is delivered via a private pipeline that connects with the Kern River-Mojave Pipeline. The pipeline was constructed by a joint venture in which the project owns approximately 21%. An affiliate of Juniper operates the pipeline. In October 2006, Badger entered into a gas supply agreement, including transportation, with Sempra Energy Trading Corporation. In March 2008, the gas agreement was extended to cover fuel procurements through April 30, 2011.

Table of Contents

Operations & Maintenance

Operations and maintenance for the Badger Creek project is performed by an affiliate of Juniper Generation, LLC under a fixed price operations and maintenance agreement. The agreement expires in 2011, but is terminable by either party upon six months' notice. The operator receives a base monthly fee, which is adjusted annually. In addition, the agreement provides for incentive fees and penalties based on the project's availability.

An affiliate of Juniper also provides all day-to-day management services required by the project and is paid a semi-annual fee for such management services based on a percentage of gross cash receipts of the project.

Factors Influencing Project Results

The Badger Creek Project derives a portion of its operating margin through energy revenues under the PG&E PPA. Energy revenues are dependent on PG&E's short-run avoided costs ("SRAC"), which is generally defined as the cost of electricity that a utility avoids incurring by purchasing the power from an independent power producer versus constructing and operating additional generating resources on its own. PG&E's SRAC is determined by the California Public Utilities Commission ("CPUC") in conjunction with input from independent power producers, investor owned utilities and consumer groups through the state utility regulatory process. SRAC has been, and continues to be, a highly contested issue resulting in numerous CPUC proceedings and litigation. Until August 2009, SRAC was based on an administratively determined formula. In August 2009, the CPUC implemented a new SRAC methodology called the market index formula ("MIF"), which includes both a market-based component and an administratively determined component. Ultimately, the CPUC is moving toward a 100% market-based SRAC.

In April 2009, California's Market Reform and Technology Update energy market ("MRTU") commenced operation. The MRTU is expected to provide a robustly traded day-ahead market for energy that reflects the avoided marginal energy costs of California's utilities. Upon the determination by the CPUC that the MRTU is functioning properly, MIF will no longer include the administratively determined component, which is expected to lower MIF pricing and create larger differences between peak and off-peak prices. Such a determination has not been made by the CPUC.

Badger is a party to settlement negotiations among other QF facilities, California's major investor-owned utilities, and numerous consumer and independent power producer groups on a new energy pricing formula and possible extensions of firm capacity payments for project with existing contracts that will resolve many outstanding issues between the parties. Many of the SRAC and MIF related CPUC proceedings and litigation have been held in abeyance pending the outcome of the settlement negotiations.

It is expected that the CPUC regulations applicable to Badger will be in a state of transition for the foreseeable future, and there can be no assurance that decisions by the CPUC will not have an adverse impact on Badger.

Rumford Project

General Description

The Rumford Project is a 85 MW multi-fuel (coal, wood waste and tire-derived fuel) circulating fluidized bed boiler cogeneration facility located in the town of Rumford, Maine, which began commercial operation in 1990 as a QF. The Rumford project is owned by Rumford Cogeneration Company Limited Partnership, a Maine limited partnership in which we own an approximate 26% limited partnership interest. The project was constructed for the dual purpose of supplying steam and electricity to an adjacent paper mill, the Rumford Paper Company, owned by a subsidiary of NewPage

Table of Contents

Corporation ("NewPage") and electricity to the local utility. The project is situated on a site leased from the adjacent NewPage paper mill. The lease expires on December 31, 2020.

Power Purchase Agreement

In February 2007, Rumford executed an Interim Financial Obligation Consolidation Agreement with Rumford Paper Company. The agreement consolidated the payment obligations of the various prior agreements between Rumford and Rumford Paper Company into a single payment obligation effective January 1, 2007. The effect of the agreement is similar to a lease wherein Rumford Paper Company assumes the risk of fuel and power price volatility as well as most operating costs. Payments under the agreement have been made quarterly to Rumford over a three year term ended December 31, 2009. During 2009, as a result of a dispute between NewPage and the limited partners regarding the making of the 2009 distributions and the economic viability of the project following the expiration of the agreement with Rumford Paper Company at the end of 2009, a settlement agreement was entered into which provided for the payment of the 2009 distributions to the partners. The settlement agreement further provided for the purchase by NewPage of the partners' interests in Rumford under certain conditions. If NewPage does purchase the partners' interests in Rumford, our share of the proceeds is expected to be approximately $2.5 million.

Koma Kulshan Project

General Description

The Koma Kulshan project is a 13.3 MW run-of-the-river hydroelectric generation facility located on the slopes of Mount Baker, approximately 80 miles north of Seattle, Washington, and began commercial operation in 1990 as a QF. The Koma Kulshan project is owned by Koma Kulshan Associates, a California limited partnership in which we own a 49.75% economic interest, Mt. Baker Corporation owns a 0.25% economic interest and Covanta Energy Corporation owns the remaining 50%. The Koma Kulshan project was issued a 50-year hydro license from the FERC which expires in 2037. The project and its electrical output is sold to Puget Sound Energy, Inc. under a PPA expiring in 2037.

Our and Mt. Baker Corporation's interests in the project are held through Concrete Hydro Partners, L.P. Under the Concrete partnership agreement, Mt. Baker Corporation is entitled to reimbursement of certain deferred costs associated with the original development of the project from a portion of the distributions from the project. The full repayment of these deferred costs is expected in 2010, following which distributions are projected to be made ratably to us and Mt. Baker Corporation.

Power Purchase Agreement

Energy generated by the Koma Kulshan project is sold to Puget Sound Energy pursuant to a long-term PPA expiring in 2037. Power is sold at a per kilowatt hour rate that is adjusted annually. The term of the PPA is coterminous with the FERC license. Puget Sound Energy has the right to renew the PPA for a term equivalent to the term of any subsequent license or annual license granted by the FERC for the project.

Operations & Maintenance

Covanta Energy Corporation performs the operations and maintenance of the facility pursuant to an operations and maintenance agreement which expires December 31, 2010. In addition to being reimbursed for actual costs incurred, Covanta receives an annual fee adjusted for inflation.

Table of Contents

Delta-Person Project

General Description

The Delta-Person Project is a 132 MW natural gas-fired peaking facility located near Albuquerque, New Mexico, is an exempt wholesale generator ("EWG") that commenced commercial operation in 2000. We own a 40% interest in Delta-Person and affiliates of Olympus Power, LLC and John Hancock Mutual Life Insurance Company own the remaining interests. The Delta-Person Project is situated on PNM's (formerly Public Service of New Mexico) retired Delta Generating Station site under a lease agreement which is co-terminus with the project's PPA. The project operates as a peaking facility, which means that it is called upon to generate electricity only during unusually high periods of demand. The Delta-Person project sells all of its electrical output to PNM under a long-term PPA that expires in 2020.

Construction of the Delta-Person project was financed through a $59.7 million construction loan that was converted to permanent project financing once commercial operation was achieved. The permanent project financing was divided into two term loans: (i) Tranche A due March 31, 2017; and (ii) Tranche B due March 31, 2019, both of which amortize over their remaining terms. Our share of the total debt outstanding at the Delta-Person project as of March 31, 2010 was $11.4 million. See "Project-Level Debt" on page 69 of this registration statement for additional details.

Power Purchase Agreement

Electrical power generated by the Delta-Person project is purchased by PNM under a PPA that will expire in 2020. PNM has the unilateral right to extend the PPA for five years by giving written notice of such extension no later than two years prior to the end of the original term of the PPA. Subject to adjustments provided for in the PPA, PNM will purchase and accept the entire output of the project when PNM calls upon the capacity. Payments consist of: (i) the energy purchase price multiplied by the kilowatt hours delivered; (ii) the capacity purchase price multiplied by the dependable capacity; (iii) the project's cost of purchasing electric service from PNM for the operations and maintenance of the facility; and (iv) any other applicable charges. In order to earn full capacity payments, the project must maintain availability of at least 90%, which the project has historically achieved.

Fuel Supply Arrangements

The project purchases fuel from PNM Gas Services, a division of PNM, with fuel costs passed through to PNM under the PPA. The project has access to an interruptible gas supply and transportation like other standard industrial customers on PNM Gas Services' system.

Operations & Maintenance

As a simple cycle peaking facility, the project operations do not require extensive staffing and technical resources. Olympus Power provides asset management services, which include operational and contractual oversight of the facility, budget setting and environmental compliance.

Factors Influencing Project Results

The Delta-Person project derives a significant portion of its operating margin through capacity payments under the PPA with PNM. The capacity payment is based on two components which adjust annually with changes in inflation and interest rates. The capacity payment may be reduced on a monthly basis if the project's availability falls below 97%. The project has rarely experienced such adjustment. Energy payments are based on a variable operations and maintenance component, a fuel component and an availability incentive. The fuel component consists of the actual price the project pays for fuel and a contract heat rate. The contract heat rate is slightly higher than the project's

Table of Contents

average operating heat rate which generates additional energy revenue, because the contract heat rate represents the price that PNM pays for power that it purchases from Delta-Person. PNM will normally choose to purchase power from higher efficiency plants during periods of reduced demand. Reduced overall economic activity and related lower demand for electricity in the past two years has resulted in lower dispatch of Delta-Person by PNM.

Biomass Development Projects

Biomass-derived power is a well-established, conventional technology. In biomass power plants, the fuel is burned in a boiler to create steam that turns a turbine to generate electricity. In general, biomass power plants are designed to be operated as baseload units. While biomass encompasses a broad range of potential fuels, our activities are focused on "wood-residue" biomass. This feedstock includes virgin wood (from forests, wood processing facilities, etc.), agricultural residues, industrial and commercial waste, etc. Our facilities are eligible for renewable energy credits and may also qualify for certain federal tax benefits, depending on their construction schedule. We are pursuing six biomass projects with partners who bring specific skills to their development, as more fully described below.

Rollcast Energy, Inc.

Rollcast Energy, Inc. develops, owns and operates renewable power plants that use wood or biomass fuel. Rollcast, based in Charlotte, North Carolina, has five 50 MW biomass power plants in various stages of development in the southeastern U.S. In March 2009, we acquired a 40% equity interest in Rollcast for $3.0 million. In March 2010, we acquired an additional 15% interest for $1.2 million and in April 2010, we invested an additional $0.8 million to bring our total ownership interest to 60%. The terms of our investment in Rollcast provide us the option, but not the obligation, to invest in Rollcast's first five biomass power plants. Two of the development projects have obtained 20-year PPAs with terms that allow for the pass-through of fuel costs to the utility customer. One of those projects has signed an agreement with two banks to co-arrange project-level debt financing and also entered into a construction agreement for its first 50 MW biomass project in Barnesville, Georgia.

Onondaga Renewables, LLC

Onondaga Renewables, LLC is a 50/50 joint venture between us and Catalyst Renewables LLC formed in December 2008 to repower our decommissioned 91 MW gas-fired cogeneration facility located in Geddes, New York. Utilizing locally acquired biomass fuel, the proposed facility is expected to have a capacity of approximately 45 MW. Onondaga is currently in the process of obtaining a PPA for the full output of the facility.

ASSET MANAGEMENT

Our asset management strategy is to partner with recognized leaders in the independent power business. Most of our projects are managed by Caithness Energy, LLC; Cogentrix Energy, Inc., a subsidiary of Goldman Sachs; and, in the case of Path 15, the Western Area Power Administration, a U.S. Federal power agency. On a case-by-case basis, Caithness, Cogentrix, and Western may provide: (i) day-to-day project-level management, such as operations and maintenance and asset management activities; (ii) partnership level management tasks, such as insurance renewals; and (iii) passive partnership level management, such as acting as limited partner. In some cases these project managers or the project partnerships may subcontract with other firms experienced in project operations, such as GE, to provide for day-to-day plant operations. In addition, employees of Atlantic Power Corporation with significant experience managing similar assets are involved in most decisions with the objective to choose value-creating transactions such as contract restructurings, asset-level refinancing, acquisitions and divestitures.

Table of Contents

Caithness Energy, LLC is one of the largest privately-held independent power producers in the United States. For over 25 years in the independent power business, Caithness, has been actively engaged in the development, acquisition and management of independent power facilities for its own account as well as in venture arrangements with other entities. Caithness operates our Auburndale, Lake and Pasco projects and provides other asset management services for our Orlando, Selkirk and Badger Creek projects.

Cogentrix Energy, Inc develops, owns, and operates independent power plants, located primarily in the U.S. Cogentrix manages the operation of the Chambers and Selkirk projects. New York-based investment firm Goldman Sachs Group acquired Cogentrix in December 2003. In November 2007, Goldman Sachs sold 80% of its interest in a number of the Cogentrix independent power plants, including Chambers and Selkirk to Energy Investors Funds, an established private equity fund manager that invests in the U.S. energy and electric power sector. Cogentrix continues to manage the Chambers and Selkirk projects.

The Western Area Power Administration ("Western") markets and delivers hydroelectric power and related services within a 15-state region of the central and western United States. Western is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from multi-use water projects. Western's transmission system carries electricity from 57 power plants operated by the Bureau of Reclamation, U.S. Army Corps of Engineers and the International Boundary and Water Commission. Together, these plants have an operating capacity of approximately 8,785 MW. Western owns and operates the Path 15 transmission line.

INDUSTRY REGULATION

Overview

In the United States, the trend towards restructuring the electric power industry and the introduction of competition in electricity generation began with the passage and implementation of the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). Among other things, PURPA, as implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided cost. The FERC defines avoided cost as the incremental cost to a utility of energy or capacity which, but for the purchase from QFs, the utility would itself generate or purchase from another source. This requirement was modified in 2005, as discussed below.

Electric transmission assets, such as our Path 15 project, are regulated by the FERC on a traditional cost-of-service rate base methodology. This approach allows a transmission company to establish a revenue requirement which provides an opportunity to recover operating costs, depreciation and amortization, and a return on capital. The revenue requirement and calculation methodology is reviewed by the FERC in periodic rate cases. As determined by the FERC, all prudently incurred operating and maintenance costs, capital expenditures, debt costs and a return on equity may be collected in rates charged.

Carbon Emissions

In the United States, government policy addressing carbon emissions continued to gain momentum over the last two years. Beginning in 2009, the RGGI was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO_2 emissions. The states have varied implementation plans and schedules. Two of these states, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. Other states and regions in the United Sates are developing similar regulations and it is expected that federal climate legislation will be established in the future.

Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the U.S. House and Senate, although passage of a bill with both

Table of Contents

elements has become less likely over the past year. Separately, the U.S. Environmental Protection Agency has asserted its right to regulate CO_2 emissions and could press forward with an initiative independent of legislative efforts.

Additionally, more than half of the U.S. states and most Canadian provinces have set mandates requiring certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass. In order to meet CO_2 reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on nuclear, natural gas, and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

Regulation Generating Projects

Ten of our power generating projects are qualified facilities under PURPA and related FERC regulations. The Delta-Person and Pasco projects are not QFs but are both EWGs under the Public Utility Holding Company Act of 2005, as amended ("PUHCA"). The generating projects with QF status and which are currently party to a power purchase agreement with a utility or have been granted authority to charge market-based rates are exempt from FERC rate-making authority. The FERC has granted seven of the projects the authority to charge market-based rates based primarily on a finding that the project lacks market power. These projects are thus not subject to FERC rate-making. The generating projects are exempt from regulation under PUHCA and the projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities.

A QF falls into one or both of two primary classes, both of which would facilitate more efficient use of fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only. With the exception of QFs, generation, transmission and distribution of electricity remained largely owned by vertically integrated electric utilities until the enactment of the Energy Policy Act of 1992 (the "EP Act of 1992") and subsequent orders in 1996, along with electric industry restructuring initiated at the state level. Among other things, the EP Act of 1992 enhanced the FERC's power to order open access to power transmission systems, contributing to significant growth in the independent power generation industry.

In August 2005, the Energy Policy Act of 2005 (the "EP Act of 2005") was enacted, which removed certain regulatory constraints on investment in utility power producers. The EP Act of 2005 also limited the requirement from PURPA that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. Finally, the EP Act of 2005 amended and expanded the reach of the FERC's corporate merger approval authority under Section 203 of the Federal Power Act.

All of our projects are subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("NERC"). NERC is a self-regulatory organization that is a non-governmental entity which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

In March 2007, the FERC issued an order approving mandatory reliability standards proposed by NERC in response to the August 2003 northeastern U.S. blackouts. As the result, users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Senior Director for Asset Management as our FERC Compliance Officer responsible for meeting the FERC and NERC requirements and an

Table of Contents

outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

Regulation Transmission Project

The revenues received by the Path 15 project are regulated by the FERC through a rate review process every three years that sets an annual revenue requirement. Under terms of the initial rate case settlement, the project must go through the FERC review every three years.

The Path 15 project's initial three-year rate period's revenue requirement expired at the end of 2007. On December 21, 2007, the Project submitted to the FERC its revenue requirement for the 2008 through 2010 period. In an order issued February 2008, the FERC allowed the rates as filed in December 2007 to go into effect subject to refund pending the outcome of the regulatory proceedings. The FERC also accepted several of the project's key methodological approaches, including use of a 13.5% return on equity. A number of parties requested rehearing on such issues. On March 23, 2009, the Path 15 project filed an uncontested settlement offer with the FERC, for rehearing in the Path 15 project's rate case proceeding. We believe that the settlement was reasonable and will not significantly impact the expected cash flow from the project. On August 3, 2009, the FERC issued an order approving the settlement. Thereafter, on October 30, 2009 the Path 15 project issued refunds reflecting the difference between the rates collected as of February 2008 pursuant to the December 2007 filing and the rates provided for under the settlement. Since May 2009, the Path 15 project has been receiving revenues based on the revenue requirement established by the settlement. Pursuant to the terms of the settlement, Path 15 is required to submit its revenue requirement for the 2011 through 2013 rate period to the FERC in February 2011. The preparation of this new rate filing will commence in the third quarter of 2010.

COMPETITION

The power generation industry is characterized by intense competition, and our projects compete against utilities, industrial companies and other independent power producers. In recent years, there has been increasing competition among generators in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the U.S. power industry.

The U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition and investment opportunities, although we believe that we will continue to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms. We compete for acquisition opportunities with numerous private equity funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and financial players. Our competitive advantages include industry knowledge, experience and contacts to better access, analyze and execute acquisition opportunities and potential partners; reputation of the firm and its executive officers; capital availability and cost; knowledge, experience and contacts in finance to flexibly access and structure advantageous leverage options. We have similar strength in asset management and optimization.

EMPLOYEES

As of June 16, 2010, we had 13 full-time employees. None of our employees is represented by any collective bargaining unit or a party to any collective bargaining agreement.

Table of Contents

ITEM 1A. RISK FACTORS.

Risks Related to Our Business and Our Projects

Our revenue may be reduced upon the expiration or termination of our power purchase agreements

Power generated by our projects, in most cases, is sold under power purchase agreements (or "PPAs") that expire at various times. For example, PPAs at our Rumford, Badger Creek and Topsham projects expire between now and the end of 2011 and represent 52 MWs of our net generating capacity. The table on page 9 of this registration statement contains details about all our projects' PPAs. In addition, these PPAs may be subject to termination in certain circumstances, including default by the project. When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

Our projects depend on their electricity, thermal energy and transmission services customers

Each of our projects rely on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. The largest customers of our power generation projects, including projects recorded under equity method of accounting, are Progress Energy Florida, Inc. ("PEF"), Tampa Electric Company ("TECO"), and Atlantic City Electric ("ACE"), which purchase approximately 40%, 15% and 11%, respectively, of the net electric generation capacity of our projects. The amount of cash available for distribution to shareholders is highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their obligations or make required payments.

Certain of our projects are exposed to fluctuations in the price of electricity

Those of our projects with no PPA or a PPAs based on spot market pricing will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time.

Our most significant exposure to market power prices is at the Selkirk and Chambers projects. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market prices or not sold at all if market prices do not support profitable operation of that portion of the facility. At Chambers, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is economical to do so, and the Chambers project shares in the profits from these sales.

Our projects may not operate as planned

The revenue generated by our projects is dependent, in whole or in part, on the amount of electric energy and steam generated by them. The ability of our projects to generate the required amount of power to be sold to customers under the PPAs is a primary determinant of the amount of cash that will be distributed from the project to us, and that will in turn be available for dividends paid to our shareholders. There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could adversely affect revenues and cash flow. To the extent that our projects' equipment requires more frequent and/or longer than forecast down times for maintenance and repair, or suffers disruptions of power generation for other reasons, the amount of cash available for dividends may be adversely affected.

In general, our projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of

Table of Contents

vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a spare transformer can be found or a replacement manufactured. If the reason for a shutdown is outside of the control of the operator, a project may be able to make a force majeure claim for temporary relief of its obligations under the project contracts such as the PPA, fuel supply, steam sales agreement, a project-level debt agreement or otherwise mitigate impacts through business interruption insurance policies. If successful, such a claim may prevent a default or reduce monetary losses under such contracts. However, a force majeure claim may be challenged by the contract counterparty and, to the extent the challenge is successful, the outage may still have a materially adverse effect on the project.

Our projects depend on suppliers under fuel supply agreements and increases in fuel costs may adversely affect the profitability of the projects

Revenues earned by our projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. To the extent possible, the projects attempt to match fuel cost setting mechanisms in supply agreements to energy payments formulas in the PPA. To the extent that fuel costs are not matched well to PPA energy payments, increases in fuel costs may adversely affect the profitability of the projects.

The amount of energy generated at the projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect our results.

Upon the expiration or termination of existing fuel supply agreements, we or our project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. There can be no assurance that we or our project operators will be able to renegotiate these agreements or enter into new agreements on similar terms. Furthermore, there can be no assurance as to availability of the supply or pricing of fuel under new arrangements and it can be very difficult to accurately predict the future prices of fuel. For example, a portion of the required natural gas at our Auburndale project and all of the natural gas required at our Lake project is purchased at market prices, but the projects' PPAs that expire in 2013 do not effectively pass through changes in natural gas prices. We have executed a hedging program to substantially mitigate this risk through 2013.

The amount of energy generated at the projects is dependent upon the availability of natural gas, coal, oil or biomass. There can be no assurance that the long-term availability of such resources will remain unchanged.

Our projects depend on a favorable regulatory regime

The profitability of our projects is in part dependent upon the continuation of a favorable regulatory climate with respect to the continuing operations and the future growth and development of the independent power industry. Should the regulatory regime in an applicable jurisdiction be modified in a manner which adversely affects the projects, including increases in taxes and permit fees, dividends to shareholders may be adversely affected. The failure to obtain all necessary licenses or permits, including renewals thereof or modifications thereto, may also adversely affect cash available for distribution.

Our operations are subject to the provisions of various energy laws and regulations

Generally, in the United States, our projects are subject to regulation by the Federal Energy Regulatory Commission, or "FERC", regarding the terms and conditions of wholesale service and rates, as well as by state agencies regarding PPAs entered into by qualifying facility projects and the siting of

Table of Contents

the generation facilities. The majority of our generation is sold by qualifying facility projects under PPAs that required approval by state authorities.

In August 2005, the Energy Policy Act of 2005 was enacted, which removed certain regulatory constraints on investment in utility power producers. The Energy Policy Act of 2005 also limited the requirement that electric utilities buy electricity from qualifying facilities to certain markets that lack competitive characteristics, potentially making it more difficult for our current and future projects to negotiate favorable PPAs with these utilities. Finally, the Energy Policy Act of 2005 amended and expanded the reach of the FERC's merger approval authority.

If any project that is a qualifying facility were to lose its status as a qualifying facility, then such project may no longer be entitled to exemption from provisions of the Public Utility Holding Company Act of 2005 or from provisions of the Federal Power Act and state law and regulations. Such project may be able to obtain exempt wholesale generator status to maintain its exemption from the provisions of the Public Utility Holding Company Act of 2005, however there can be no assurance provided that our projects will be able to obtain such exemptions. Loss of qualifying facility status could trigger defaults under covenants to maintain qualifying facility status in the PPAs, steam sales agreements and project-level debt agreements and if not cured within allowed cure periods, could result in termination of agreements, penalties or acceleration of indebtedness under such agreements, plus interest.

Our projects would also have to file with the FERC for market-based rates or file for acceptance for filing of the rates set forth in the applicable PPA, and our projects' rates would then be subject to initial and potentially subsequent reviews by the FERC under the Federal Power Act, which could result in reductions to the rates.

Our projects require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable regulations, our business, results of operations and financial condition could be adversely affected.

The Energy Policy Act of 2005 provides incentives for various forms of electric generation technologies, which may subsidize our competitors. In addition, pursuant to the Energy Policy Act of 2005, the FERC selected an electric reliability organization which imposes mandatory reliability rules and standards. Among other things, the FERC's rules implementing these provisions allow such reliability organizations to impose sanctions on generators that violate their new reliability rules.

We cannot provide assurance that the introductions of new laws, or other future regulatory developments, will not have a material adverse impact on our business, operations or financial condition.

Future Federal Energy Regulation Commission rate determinations could negatively impact Path 15's cash flows

The stability of Path 15's cash flows will continue to be subject to the risk of the FERC's adjusting the expected formulation of revenues upon its rate review every three years. The cost-of-service methodology currently applied by the FERC is well established and transparent; however, certain inputs in the FERC's determination of rates are subject to its discretion, including in response to protests from interveners in such rate cases, which include return on equity and the recovery of certain extraordinary expenses. Unfavorable decisions on these matters could adversely affect the cash flow, financial position and results of operations of us and Path 15, and could adversely affect our cash available for dividends.

Table of Contents

Noncompliance with federal reliability standards may subject us and our projects to penalties

Our operations are subject to the regulations of the North American Electric Reliability Corporation ("NERC"), a self-regulatory organization that is a non-governmental entity which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators. NERC groups the users, owners, and operators of the bulk power system into 17 categories, known