Pattern Energy Group Inc.
Form 10-K
February 29, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2015.

-OR-

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

Commission File Number 001-36087

PATTERN ENERGY GROUP INC.
(Exact name of Registrant as specified in its charter)

Delaware	90-0893251
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Pier 1, Bay 3, San Francisco, CA 94111
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (415) 283-4000
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Class A Common Stock, par value $0.01 per share	NASDAQ Global Select Market Toronto Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

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

The aggregate market value of the voting stock and non-voting stock held by non-affiliates of the registrant based upon the last trading price of the registrant's Class A common stock as reported on the NASDAQ Global Market on June 30, 2015 was approximately $1,462,489,654. This excludes 17,705,514 shares of Class A common stock held by directors, officers and Pattern Renewables LP and certain of its affiliates. Exclusion of shares does not reflect a determination that persons are affiliates for any other purpose.

The registrant's Class A common stock began trading on the NASDAQ Global Market under the symbol "PEGI" and on the Toronto Stock Exchange under the symbol "PEG" on October 2, 2013.

On February 24, 2016, the registrant had 74,643,763 shares of Class A common stock, $0.01 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement relating to its 2016 annual meeting of stockholders (the "2016 Proxy Statement") are incorporated by reference into Part III of this Form 10-K where indicated. The 2016 Proxy Statement will be filed with the U.S. Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates.

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CAUTIONARY NOTICE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K ("Form 10-K") contains statements that may constitute forward-looking statements. You can identify these statements by forward-looking words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "potential," "should," "will," "would," or similar words. You should read statements that contain these words carefully because they discuss our current plans, strategies, prospects, and expectations concerning our business, operating results, financial condition, and other similar matters. While we believe that these forward-looking statements are reasonable as and when made, there may be events in the future that we are not able to predict accurately or control, and there can be no assurance that future developments affecting our business will be those that we anticipate. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause our actual results to differ from those in the forward-looking statements, include but are not limited to, those summarized below and further described in Part I, Item 1A "Risk Factors:"

- our ability to complete acquisitions of power projects;
- our ability to complete construction of construction projects and transition them into financially successful operating projects;
- fluctuations in supply, demand, prices and other conditions for electricity, other commodities and renewable energy credits ("RECs");
- our electricity generation, our projections thereof and factors affecting production, including wind and other conditions, other weather conditions, availability and curtailment;
- changes in law, including applicable tax laws;
- public response to and changes in the local, state, provincial and federal regulatory framework affecting renewable energy projects, including the U.S. federal production tax credit ("PTC"), investment tax credit ("ITC") and potential reductions in Renewable Portfolio Standards ("RPS") requirements;
- the ability of our counterparties to satisfy their financial commitments or business obligations;
- the availability of financing, including tax equity financing, for our power projects;
- an increase in interest rates;
- our substantial short-term and long-term indebtedness, including additional debt in the future;
- competition from other power project developers;
- development constraints, including the availability of interconnection and transmission;
- potential environmental liabilities and the cost and conditions of compliance with applicable environmental laws and regulations;
- our ability to operate our business efficiently, manage capital expenditures and costs effectively and generate cash flow;
- our ability to retain and attract executive officers and key employees;
- our ability to keep pace with and take advantage of new technologies;
- the effects of litigation, including administrative and other proceedings or investigations, relating to our wind power projects under construction and those in operation;
- conditions in energy markets as well as financial markets generally, which will be affected by interest rates, foreign currency exchange rate fluctuations and general economic conditions;
- the effectiveness of our currency risk management program;
- the effective life and cost of maintenance of our wind turbines and other equipment;
- the increased costs of, and tariffs on, spare parts;
- scarcity of necessary equipment;
- negative public or community response to wind power projects;
- the value of collateral in the event of liquidation; and
- other factors discussed under "Risk Factors."

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

MEANING OF CERTAIN REFERENCES

Unless the context provides otherwise, references herein to "we," "our," "us," "our company" and "Pattern" refer to Pattern Energy Group Inc., a Delaware corporation, together with its consolidated subsidiaries. In addition, unless the context requires otherwise, any reference in this Form 10-K to:

- "Conversion Event" refers to the event pursuant to which all of our Class B shares automatically converted into Class A shares on a one-for-one basis on December 31, 2014;
- "employee transfer" refers to the event contemplated by the Management Services Agreement pursuant to which we have the option, exercisable by delivery of written notice of exercise to Pattern Development at any time during a period of eighteen (18) months commencing July 1, 2015, to require Pattern Development to cause the employees of Pattern Development and its subsidiaries to become employees of us and our subsidiaries. From and after the occurrence of the employee transfer event, we and Pattern Development will cooperate to cause such employee transfer to occur by the six month anniversary of the employee transfer event or as soon as reasonably practical thereafter;
- "FERC" refers to the U.S. Federal Energy Regulatory Commission;
- "FIT" refers to feed-in-tariff regime;
- "FPA" refers to the Federal Power Act;
- "Identified ROFO Projects" refers to thirteen projects that we identified as development projects, each owned by Pattern Development and subject to our Project Purchase Right, consisting of Armow, Meikle, Conejo Solar, Belle River, Henvey Inlet, Mont Sainte-Marguerite, North Kent, Broadview projects, Grady, Tsugaru, Ohorayama, Kanagi Solar and Futtsu Solar projects. The Tsugaru, Ohorayama, Kanagi Solar and Futtsu Solar projects are held through Pattern Development’s majority stake investment in Green Power Investment Corporation ("GPI") based in Tokyo, Japan;
- "IPPs" refers to independent power producers;
- "ISOs" refers to independent system organizations, which are organizations that administer wholesale electricity markets;
- "ITCs" refers to investment tax credits;
- "Management Services Agreement" refers to the bilateral services agreement between us and Pattern Development, as amended;
- "MW" refers to megawatts;
- "MWh" refers to megawatt hours;
- "Non-Competition Agreement" refers to a non-competition agreement between us and Pattern Development pursuant to which Pattern Development agrees that, for so long as any of our Purchase Rights are exercisable, it will not compete with us for acquisitions of power generation or transmission projects from third parties;
- "OCC" refers to our operations control center;
- "Pattern Development" refers to Pattern Energy Group LP and its subsidiaries (other than us and our subsidiaries);
- "Pattern Development Purchase Rights" refer to the right to acquire Pattern Development itself or substantially all of its assets, as contemplated by the Purchase Rights Agreement between us and Pattern Development;
- "power sale agreements" refer to PPAs and/or hedging arrangements, as applicable;
- "PPAs" refer to power purchase agreements;

- "Project Purchase Right" refers to a right of first offer with respect to any power project that Pattern Development decides to sell, including the Identified ROFO Projects;
- "Purchase Rights" refer to the Project Purchase Right and the Pattern Development Purchase Rights, as contemplated by the Purchase Rights Agreement between us and Pattern Development;
- "RECs" refers to renewable energy credits;
- "Riverstone" refers to Riverstone Holdings LLC;
- "ROFO" refers to right of first offer;
- "RPS" refers to Renewable Portfolio Standards;
- "Sarbanes-Oxley Act" refers to the Sarbanes-Oxley Act of 2002;
- "Samsung" means Samsung C&T Corporation; and
- "U.S. Treasury" refers to the U.S. Department of the Treasury.

CURRENCY AND EXCHANGE RATE INFORMATION

In this Form 10-K, references to "C$" and "Canadian dollars" are to the lawful currency of Canada and references to "$", "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 stated.

Our historical consolidated financial statements are presented in U.S. dollars. The following chart sets forth for each of 2015, 2014 and 2013, the high, low, period average and period end noon buying rates of Canadian dollars expressed as Canadian dollars per US$1.00.

	Canadian Dollars per US$1.00							
	High		Low		Period Average(1)		Period End	
Year								
2015	C$	1.3987	C$	1.1601	C$	1.2788	C$	1.3835
2014		1.1643		1.0614		1.1045		1.1501
2013		1.0697		0.9839		1.0300		1.0637

(1) The average of the noon buying rates on the last business day of each month during the relevant one-year period and, in respect of monthly or interim period information, the average of the noon buying rates on each business day for the relevant period.

The noon buying rate in Canadian dollars on February 24, 2016 was US$1.00 = C$1.3707.

The above rates differ from the actual rates used in our consolidated historical financial statements and the calculation of cash available for distribution and dividends we declared and paid described elsewhere in this Form 10-K. Our inclusion of these exchange rates is not meant to suggest that the U.S. dollar amounts actually represent such Canadian dollar amounts or that such amounts could have been converted into Canadian dollars at any particular rate or at all.

For information on the impact of fluctuations in exchange rates on our operations, see Item 1A "Risk Factors—Risks Related to Our Projects—Currency exchange rate fluctuations may have an impact on our financial results and condition" and Item 7A "Quantitative and Qualitative Disclosure About Market Risk—Foreign Currency Exchange Rate Risk."

PART I

Item 1. Business.

Overview

We are an independent power company focused on owning and operating power projects with stable long-term cash flows in attractive markets with potential for continued growth of our business. We hold interests in 16 wind power projects located in the United States, Canada and Chile that use proven, best-in-class technology and have a total owned capacity of 2,282 MW. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement. Eighty-nine percent of the electricity to be generated by our projects will be sold under our power sale agreements which have a weighted average remaining contract life of approximately 14 years.

Our growth strategy is focused on the acquisition of operational and construction-ready power projects from Pattern Development and other third parties that we believe will contribute to the growth of our business and enable us to increase our dividend per Class A share over time. Pattern Development is a leading developer of renewable energy and transmission projects. We believe Pattern Development's ownership position in our company incentivizes Pattern Development to support the successful execution of our objectives and business strategy, including through the development of projects to the stage where they are at least construction-ready. Currently, Pattern Development has a 5,900 MW pipeline of development projects, all of which are subject to our right of first offer. We target achieving a total owned capacity of 5,000 MW by year end 2019 through a combination of acquisitions from Pattern Development and other third parties capitalizing on the large and fragmented global renewable energy market. In addition, we expect opportunities in Japan and Mexico will form part of our growth strategy.

Our Core Values and Financial Objectives

We intend to maximize long-term value for our stockholders in an environmentally responsible manner and with respect for the communities in which we operate. Our business is built around three core values of creative energy and spirit, pride of ownership and follow-through, and a team first attitude, which guide us in:

- creating a safe and high-integrity work environment for our employees;
- applying rigorous analysis to all aspects of our business in a timely, disciplined and functionally integrated manner to understand patterns in wind regimes, technology developments, market trends and regulatory, financial and legal constraints; and
- working proactively with our stakeholders to address environmental and community concerns, which we believe is a socially responsible approach that also benefits our business by reducing operating risks at our projects.

Our financial objectives, which we believe will maximize long-term value for our stockholders, are to:

- produce stable and sustainable cash available for distribution;
- selectively grow our project portfolio and our dividend per Class A share; and
- maintain a strong balance sheet and flexible capital structure.

Our Projects

The following table provides an overview of our wind projects:

	Location and Start-up			Capacity (MW)		Power Sale Agreements				
Projects	Location	Construction Start[1]	Commercial Operations[2]	Rated[3]	Owned[4]	Type	Contracted Volume[5]	Counterparty	Counterparty Credit Rating[6]	E
Operating Projects										
Gulf Wind	Texas	Q1 2008	Q3 2009	283	283	Hedge[7]	~58%	Morgan Stanley	BBB+/A3	2
Hatchet Ridge	California	Q4 2009	Q4 2010	101	101	PPA	100%	Pacific Gas & Electric	BBB/A3	2
St. Joseph	Manitoba	Q1 2010	Q2 2011	138	138	PPA	100%	Manitoba Hydro	AA/Aa2[8]	2
Spring Valley	Nevada	Q3 2011	Q3 2012	152	152	PPA	100%	NV Energy	BBB+/Baa2	2
Santa Isabel	Puerto Rico	Q4 2011	Q4 2012	101	101	PPA	100%	Puerto Rico Electric Power Authority	CC/Caa3	2
Ocotillo	California	Q3 2012	Q4 2012	223	223	PPA	100%	San Diego Gas & Electric	A/A1	2
Ocotillo	California		Q2 2013	42	42	PPA	100%	San Diego Gas & Electric	A/A1	2
South Kent	Ontario	Q1 2013	Q2 2014	270	135	PPA	100%	Independent Electricity System Operator	Aa2[9]	2
El Arrayán	Chile	Q3 2012	Q2 2014	115	81	Hedge[10]	~74%	Minera Los Pelambres	NA	2
Panhandle 1	Texas	Q3 2013	Q2 2014	218	172	Hedge[11]	~80%	Citigroup Energy Inc.	BBB+/Baa1	2
Panhandle 2	Texas	Q4 2013	Q4 2014	182	147	Hedge[11]	~80%	Morgan Stanley	BBB+/A3	2
Grand	Ontario	Q3 2013	Q4 2014	149	67	PPA	100%	Independent Electricity System Operator	Aa2[9]	2
Post Rock	Kansas	Q4 2011	Q4 2012	201	120	PPA	100%	Westar Energy, Inc.	BBB+/Baa1	2
Lost Creek	Missouri	Q2 2009	Q2 2010	150	150	PPA	100%	Associated Electric Cooperative, Inc.	AA/A2	2
K2	Ontario	Q1 2014	Q2 2015	270	90	PPA	100%	Independent Electricity System Operator	Aa2[9]	2
Logan's Gap	Texas	Q4 2014	Q3 2015	200	164	PPA	~58%	Wal-Mart Stores, Inc.	AA/Aa2	2

						Hedge[12]	~17%	Merrill Lynch Commodities, Inc.	BBB+/Baa1	2
Amazon Wind Farm Fowler Ridge	Indiana	Q2 2015	Q4 2015	150	116	PPA	100% [13]	Amazon.com, Inc.	AA-/Baa1 [14]	2
				2,945	2,282					

(1) Represents date of commencement of construction.

(2) Represents date of actual or anticipated commencement of commercial operations.

(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated may be less than its rated capacity.

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(4) Owned capacity represents the maximum, or rated, electricity generating capacity of the project in MW multiplied by our percentage ownership interest in the distributable cash flow of the project.
(5) Represents the percentage of a project's total estimated average annual MWh of electricity generation contracted under power sale agreements or hedge arrangements.
(6) Reflects the counterparty's or counterparty guarantor's corporate credit ratings issued by either S&P or Moody's, or both S&P and Moody's, as of December 31, 2015.
(7) Represents a 10-year fixed-for-floating power price swap. See Item 2 "Properties—Operating Projects—Gulf Wind."
(8) Reflects the corporate credit ratings of the Province of Manitoba, which owns 100% of Manitoba Hydro-Electric.
(9) Reflects the corporate credit ratings of the Province of Ontario, which owns 100% of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority.
(10) Represents a 20-year fixed-for-floating swap. See Item 2 "Properties—Operating Projects—El Arrayán."
(11) Represents a fixed-for-floating swap of more than ten years duration. See Item 2 "Properties—Operating Projects—Panhandle 1 and Panhandle 2."
(12) Represents a 13-year fixed-for-floating swap. See Item 2 "Properties—Operating Projects—Logan's Gap."
(13) Contracted volume begins at 50% and increases pro rata to 100% over a period of 18 months, beginning January 2016.
(14) Contractual counterparty is a wholly-owned subsidiary of Amazon Web Services and obligations are guaranteed by Amazon.com, Inc.

Each of our projects has gone through a rigorous vetting process in order to meet our investment and our lenders' financing criteria. As a result, our projects generally have the following characteristics:

- multi-year on-site wind data analysis tied to one or more long-term wind energy reference sources. Pattern Development employs a full-time meteorological team that manages and verifies third party wind analysis. This wind analysis is carefully vetted through detailed studies by internal and independent experts in meteorology and statistics to derive an expected production profile based on daily and seasonal wind patterns, structural interference, topography and atmospheric conditions. Our average on-site wind data collection is over four years (or approximately seven years including post-construction data collection);
- long-term power sale agreements designed to ensure a predictable revenue stream. As is typical in our industry, we sell our electricity at a fixed price on a contingent, as-produced basis such that only the electricity that we generate is sold to and must be purchased by the counterparty at the agreed price. Our power sale agreements have a weighted average remaining contract life of approximately 14 years;
- contractually secured real estate property and easement rights for a period well in excess of the project's expected useful life and contractual obligations. Each of our projects has land rights for 25 years or more;
- a firm right to interconnect to the electricity grid through interconnection agreements, which define the cost allocation and schedule for interconnection, as well as any upgrades required to connect the project to the transmission system. Our interconnection agreements allow our projects to connect to the electricity transmission system. Market rules and protocols generally govern dispatch of our electricity generation and allow it to flow freely into the grid as it is produced, except in very limited circumstances where our projects can be curtailed, for example during system emergencies;
- long-term, limited-recourse, amortizing project financing designed to match the long-lived nature of our power projects and the related power sales agreements. The interest rates on our long-term loans are fixed for the tenor of the loans or are subject to fixed-for-floating swaps that match the amortization schedules of the debt;
- all necessary construction and operating permits and other requisite federal, state or provincial and local permits, and regulatory approvals secured, which critical permits typically include federal aviation, state or provincial environmental approvals and local zoning and land-use permits and are designed to protect the community, cultural resources, plants, animal and other affected resources at or near the facility;
- fixed-price turbine supply and construction contracts with guaranteed completion dates to ensure that our projects are completed on time and within the estimated budget. The construction period for our projects has typically been less

than one year, although in certain instances circumstances warrant a longer construction period;

- an operations and maintenance service program based on our own on-site personnel and central operations management as well as equipment warranties and service arrangements with qualified contractors experienced in wind project maintenance. We have existing turbine equipment warranties for approximately 75% of our operating turbine units; and
- safety, environmental and community programs to support our existing projects and relationships in the communities in which we operate.

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For additional information regarding each of our projects, see Item 2 "Properties." Our ability to transition each of our construction projects to commercial operations and achieve anticipated power output at all of our operating projects is subject to numerous risks and uncertainties as described under Item 1A "Risk Factors."

Our Business Strategy

We intend to make profitable investments in environmentally responsible power projects, while embracing a long-term commitment to the communities in which we operate. To achieve our financial objectives while adhering to our core values, we intend to execute the following business strategies:

Maintaining and Increasing the Value of Our Projects

We intend to efficiently operate our projects to meet projected revenue and cash available for distribution. We expect to maximize the long-term value of our projects by focusing on value-oriented project availability (by ensuring our projects are operational when the wind is strong and PPA prices are at their highest) and by regularly scheduled and preventative maintenance. We believe that good operating performance begins with a long-term maintenance program for our equipment. We also seek to improve performance or lower operating costs by working closely with our equipment vendors and considering contracting with third parties, when appropriate.

We believe it is important to employ our own personnel in aspects of our business that we deem critical to the value of our projects but to contract with reliable third parties for on-going major maintenance of our turbines and similar specialized services such as repairs on our substations or transmission lines. As a result, we employ on-site personnel, maintain a 24/7 operations control center to monitor our projects and control all critical aspects of commercial asset management.

Selectively Growing Our Business

Our strategy for growth is focused on the acquisition of operational and construction-ready power projects from Pattern Development and other third parties that we believe will contribute to the growth of our business and enable us to increase our dividend per Class A share over time. We expect that projects we may acquire in the future will represent a logical extension of our existing business and be consistent with our risk profile, and that any incremental assumption of risk will require commensurate expectations of higher returns. As a result, our near-term growth strategy will remain focused on largely contracted cash flows with creditworthy counterparties and operating or in-construction projects.

We expect that new opportunities will arise from our relationship with Pattern Development, which provides us with the opportunity to acquire projects that it successfully develops and efficiently completing construction and achieving commercial operations at these projects.

Below is a summary of the Identified ROFO Projects that we expect to acquire from Pattern Development in connection with our Project Purchase Right.

Identified ROFO Projects	Status	Location	Construction Start(1)	Commercial Operations(2)	Contract Type	Capacity (MW) Rated(3)	Pattern Development-Owned(4)
Armow	Operational	Ontario	2014	2015	PPA	180	90
Meikle	In construction	British Columbia	2015	2016	PPA	180	180
Conejo Solar	In construction	Chile	2015	2016	PPA	104	84
Belle River	Securing final permits	Ontario	2016	2017	PPA	100	50
Henvey Inlet	Late stage development	Ontario	2016	2017	PPA	300	150
Mont Sainte-Marguerite	Late stage development	Québec	2016	2017	PPA	147	147
North Kent	Late stage development	Ontario	2016	2017	PPA	100	43
Broadview projects	Late stage development	New Mexico	2016	2017	PPA	324	259
Grady	Late stage development	New Mexico	2016	2017	PPA	220	176
Tsugaru	Late stage development	Japan	2015	2018	PPA	126	63
Ohorayama	Late stage development	Japan	2015	2017	PPA	33	31
Kanagi Solar	In construction	Japan	2014	2016	PPA	14	6
Futtsu Solar	Operational	Japan	2014	2016	PPA	42	19
						1,870	1,298

(1) Represents date of actual or anticipated commencement of construction.

(2) Represents date of actual or anticipated commencement of commercial operations.

(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated may be less than its rated capacity.

(4) Pattern Development-owned capacity represents the maximum, or rated, electricity generating capacity of the project in MW, multiplied by Pattern Development's percentage ownership interest in the distributable cash flow of the project.

Our management team will rigorously review and analyze new market opportunities and selectively consider opportunities offered by Pattern Development as well as those offered by other third parties, either independently or jointly with Pattern Development. From time to time, we may submit bids in connection with third party acquisition opportunities, including opportunities to purchase the interests of projects held by our joint venture partners. These bids can be binding bids or non-binding bids, can be for single assets or a group of assets, and (if accepted) can be material acquisitions for us. There can be no assurance any such bids will be accepted.

Completing Our Construction Projects on Schedule and Within Budget

We promote our business by completing our construction projects on schedule and within budget, transitioning projects under construction to commercial operation on a timely basis and efficiently operating our projects to maximize project revenues and minimize operating costs. We utilize experienced, creditworthy contractors and proven technology to build high-quality power projects. In 2015, we completed construction at two construction projects which increased our owned capacity by 280 MW, for an aggregate of 2,282 MW together with our other operating projects.

Maintaining a Prudent Capital Structure and Financial Flexibility

We intend to maintain a conservative approach to our capital structure to protect our ability to pay regular dividends and fund investments to provide for future growth. Power projects by their nature require significant upfront capital investment and as a result we believe it prudent to match these long-lived assets with long-term debt and/or equity. The average maturity of our project-level term debt is approximately 12 years, although our scheduled loan amortization is typically 18 years or more, and we have an expected average annual debt service coverage ratio over the remaining scheduled loan amortization periods of more than 1.7 to 1.0. This prudent capital structure coupled with our predictable price for our electricity and our standard operations and maintenance programs help to achieve a stable cash flow profile.

Consistent with our existing indebtedness, we expect to typically utilize fixed-rate indebtedness (or swapping any variable rate indebtedness) with strong debt service coverage ratios to finance projects. We believe this approach, together with a strategic consideration of project-level financial restructuring and recapitalization opportunities, will contribute to our ability to maintain and, over time, increase our cash available for distribution.

Working Closely With Our Stakeholders

We believe that close working relationships with our various stakeholders, including suppliers, power sales agreement counterparties, regulators, the local communities where we are located and environmental organizations and with Pattern Development and other developers enable us to best support our existing projects and will help us access attractive, construction-ready projects.

Employee Transfer of Pattern Development Employees

In 2015, we amended our Management Services Agreement with Pattern Development to change the terms upon which the employees of Pattern Development will become our employees. We refer to this event as the employee transfer. The employee transfer is no longer conditioned upon our achievement of $2.5 billion in market capitalization. Instead, we have the option, exercisable at any time until January 1, 2017, to require the employee transfer to occur. We will not be required to make any payments to Pattern Development upon the occurrence of the employee transfer, other than the payment of any statutory severance payments that may as a result be due and payable to employees in certain jurisdictions outside the United States. The employee transfer will result in our complete internalization of the administrative, technical and other services that were initially provided to us by Pattern Development under the Management Services Agreement. The occurrence of the employee transfer will neither alter our Purchase Rights nor the terms of the Management Services Agreement.

Upon the employee transfer, we expect that our principal focus will continue to be owning operational and under-construction power projects. However, the employee transfer is expected to enhance our long-term ability to independently develop projects and grow our business. Following the employee transfer, we will continue to provide management and other services to Pattern Development (including services from the reintegrated departments of Pattern Development) to the extent required by Pattern Development’s remaining development activities, and Pattern Development will continue to pay us for those services primarily on a cost reimbursement basis.

Competitive Strengths

We believe our key competitive strengths include:

Our High-Quality Projects

We believe our high-quality projects are better positioned to generate stable long-term cash flows compared to typical projects in the industry and will generate available cash in excess of our initial dividend level, providing us the financial resources for investing in new opportunities. Having high-quality projects also provides us access to low-cost project-level debt and strong stakeholder relationships. The key attributes and strengths of our projects are:

Long-Term, Fixed-Price Power Sale Agreements. We believe our long-term, fixed-price power sale agreements with 14 distinct creditworthy counterparties will deliver stable long-term revenues, although we note that the credit rating of the Puerto Rico Electric Power Authority, or "PREPA," counterparty to our Santa Isabel project’s PPA, was downgraded a number of times in each of 2014 and 2015. Our power sale agreements cover 89% of the electricity to be generated across our projects with a weighted average remaining contract life of approximately 14 years.

Geographically Diverse Markets and Wind Regimes. Our geographically diverse projects are located across regions generally characterized by high demand for renewable energy, documented reliable wind resources, deregulated energy markets and favorable renewable energy policies. The geographic diversity of our projects—from California to Puerto Rico, and Manitoba to Chile—helps insulate us against regional wind fluctuations as well as the possibility of adverse regulatory conditions in any one jurisdiction.

State-of-the-Art Wind Turbine Technologies. Our projects utilize state-of-the-art, proven, reliable wind turbine technologies. Our projects utilize Siemens 2.3 MW, Mitsubishi MWT95/2.4, General Electric 1.5-82.5 and 1.85-87 wind turbines, some of the most reliable and proven turbine technologies available in the market. The wind turbines were in each case specifically selected for the site conditions to ensure optimal performance and longevity of the machines. Our turbines have an average age of approximately three years.

Our Strong Reputation in the Industry

We believe the success of our team has created a highly respected organization which attracts talented people and new opportunities. Our integrity, expertise, and solutions-oriented approach is attractive to stakeholders and parties providing services to our existing projects as well as those who are looking for buyers of their assets.

In 2015, the Conejo Solar project, which is on our list of identified ROFO projects, won the Chilean International Renewable Energy Congress's ("CIREC") "Latin American Renewables Deal of the Year". In 2013, our Ocotillo project received an award for its outstanding environmental analysis and documentation from the California Association of Environmental Professionals and also received the Renewable Project Finance Deal of the Year award from Power Finance & Risk published by Power Intelligence. Our Spring Valley project received the Wind Project of the Year Award in 2012 from POWER-GEN International (the publisher of Power Engineering and Renewable Energy World), which we believe is considered among the most prestigious awards in the renewable energy industry. Our El Arrayán project also won two Chilean International Renewable Energy Awards, presented at CIREC's 2012 annual conference in Santiago. The awards were the Best Renewable Energy Project in 2012 (Mejor proyecto de Energía Renovable de 2012) and the Best Renewable Energy Joint Venture (Mejor colaboración entre dos empresas).

Our Approach to Project Selection

Our approach to project selection aims to deliver superior financial results and minimize long-term operating risks by focusing on the acquisition of projects that are operational or construction-ready and have long-term power sales agreements with creditworthy counterparties. Once we identify an attractive opportunity, we apply rigorous analysis in a timely, disciplined and functionally integrated manner to evaluate the wind regime, technology options, site design improvement, regional market trends and regulatory, financial and legal constraints. The most attractive projects offer the proper combination of land accessibility, power transmission capacity, attractive power sales markets and favorable and dependable winds. We believe the members of our management team are recognized by their industry peers as skilled in identifying, analyzing and executing successful power project acquisitions.

Our approach to project selection has also enabled us to successfully execute new projects in a complex renewable energy market characterized by economic, political and regulatory changes that affect energy investment opportunities. Examples include the cyclical nature of U.S. federal incentives and the challenge of realizing the full value of these incentives, volatility in the equity markets, increasing environmental and permitting concerns, reduced PPA opportunities that are influenced by changing power markets, a cyclical wind turbine supply environment that alternates between tight and loose supply constraints, changes in wind turbine technology, changes in availability of debt markets, and changes in electricity market structure. Our management team has had success in identifying and executing attractive acquisitions through all of these changing circumstances. For example, through our innovative approach to our business, we developed a financial structure to realize value for PTCs, implemented ground-breaking radar technology to protect bird and bat populations, became one of the first IPPs to capture value from a number of newly deregulated markets and found long-term debt solutions even when the debt markets were highly constrained.

As a fundamental principle, we seek to acquire projects that will contribute measurable improvements in our adjusted EBITDA and our cash available for distribution and that will have a risk profile consistent with our current business objectives. In addition, we view projects as long-term partnerships with all stakeholders, and the benefits that we pledge to the community are fundamental to creating a positive environment for a project’s long-term success.

Our Relationship with Pattern Development

Our continuing relationship with Pattern Development, for which Pattern Energy's ownership interest is 23%, provides us with access to a pipeline of acquisition opportunities. We believe Pattern Development’s ownership position in our company incentivizes Pattern Development to support the successful execution of our objectives and business strategy, including through the preparation of projects to the stage where they are at least construction-ready. We believe Pattern Development’s focus on project development combined with our Project Purchase Right will complement our acquisition strategy, which focuses on the identification and acquisition of operational and construction-ready power projects.

Organization of Our Business

Our business is organized around our current projects. In the future, we expect that our business will include additional operating and construction-ready projects acquired from Pattern Development and other third parties. In addition to our executive officers, we employ 116 full-time staff in key functional areas associated with construction and engineering, operations and maintenance, and commercial management. We rely on some services to be performed by third parties, including Pattern Development, but have all the core functions required for the overseeing of constructing, operating and managing our projects.

Operations and Maintenance

Our operations team's objective is to maximize revenues from each of our projects. In order for us to maximize our revenues, we seek to operate and maintain our equipment so that we can ensure our equipment is productive during times of optimal wind resources and power prices. Our approach to achieving efficient operations involves the following key strategic objectives:

- Safety. We believe that the safety of our workers, our contractors, our visitors and the community is paramount and takes precedence over all other aspects of operations. We demonstrate this through promoting a strong safety culture, implementing a formal safety management program, employing a full time in-house safety organization and conducting annual site safety audits.
- Equipment reliability and fleet management. We have selected high-quality equipment with a goal of having a concentration of equipment from top manufacturers. We employ the Siemens 2.3 MW turbine at 12 of our 16 project sites, the Mitsubishi MWT95/2.4 at one site, the General Electric 1.5-82.5 at two sites and the General Electric 1.85-87 at the remaining site. With a combination of high-quality equipment and scale, we have structured our fleet such that we may:
- expect high availability and long-term production from the equipment;
- continue developing operating expertise and experience, which can be shared among our operators;
- obtain a high level of attention and focus from the manufacturer; and
- maintain a shared spare parts inventory and common operating practices.
- Long-term service and maintenance. Good operating performance begins with a long-term maintenance approach to the equipment. While approximately 75% of our operating turbine units remain under original or extended warranty, on-going maintenance and replacement of parts is essential to equipment longevity. All of our wind turbines are managed either under service or warranty agreements that ensure regular repair and replacement of parts.
- Inspection. As our warranty contracts and service arrangements expire, we conduct extensive third-party end of warranty inspections to identify any potential equipment or service issues which can be remedied by the manufacturer pursuant to their contractual obligations under the warranty and ensure the projects start their post-warranty periods with reliably functioning equipment.
- Staff training. We employ highly experienced personnel from a variety of power generation sectors. In addition, we bring into the organization a broad base of best industry practices. After hiring, we provide our operators with on-going training, in-house and from manufacturers and from third parties, to keep them current on latest industry practices and experiences.
- Focus on our value-added capabilities. In order to maximize efficiencies, we concentrate our resources on our core operating areas. In particular, we believe it is critical to have on-site management personnel that are our employees and provide oversight of all site activities to ensure our safety and financial objectives have priority. We contract with third parties, often the turbine manufacturer, for on-going major maintenance of the turbines and similar specialized services such as repairs on our substations or transmission lines.
- Maximize structural efficiencies. Our operating resources are allocated across three key areas, site operations, our 24/7 OCC and other central support services.
- Site-operators. All of our projects have our employees as on-site operators, which allows for direct management of the projects and all contractors working on site. In addition, these individuals also strive for a high level of involvement in the communities we serve, including with respect to our power purchasers, the regulatory agencies and local communities. Each of our projects has the latest, state-of-the-art supervisory control and data acquisition systems that help us efficiently assess operating faults and plan preventative maintenance.
- 24/7 Operations Control Center. Our OCC, located in Houston, Texas, focuses on monitoring and controlling each of our wind turbines to prevent downtime, monitoring regional and local climate, tracking real time market prices and, for some of our projects, monitoring certain environmental activities. In addition, the OCC supports various other central activities such as safety, power marketing, and regulatory compliance, and it maintains constant communications with each of our site operators, which frees our site operators to concentrate on day-to-day equipment and safety activities.

- Central Support Services. In addition to our OCC, our Houston office also hosts the balance of our operations organization which provides critical support to the operating projects. This team includes our operations management team and specialists in safety, environmental management, regulatory compliance, contract management, turbine specialists and asset administration.

- Equipment improvements. We believe that our foundation of reliable and proven equipment allows us to make further operating improvements over time. For example, in 2015, we implemented certain control upgrades and blade modifications at our Post Rock and Lost Creek sites. We are also in continuing discussions with the turbine manufacturers and other innovative suppliers regarding new technologies to identify additional promising solutions which will improve our projects' performance and increase our electricity generation.

Commercial Management

Our commercial management group is tasked with protecting the long-term value of our projects' commercial arrangements. We have adopted a commercial strategy of managing our projects and other assets with an in-house commercial management group acting as "owners' representatives." The role of the commercial management group is to oversee contract management, environmental management, community relations, power marketing and finance and to closely monitor the performance of each project from an owner's point of view in order to maximize financial performance and minimize risk. Although the commercial management group manages the day-to-day aspects of commercial management, functional and managerial expertise is often brought in to support key areas such as legal, finance and power marketing.

- Contract Management. With a group of seasoned managers, our commercial management group optimizes the commercial performance of our assets, services the project debt, manages project agreements and compliance with relevant laws, regulations and rules and has ultimate responsibility for the financial performance of each project. The team also manages our real estate obligations as well as our corporate insurance program, local government obligations, home office, remote facilities and mobile assets. Our commercial management group also facilitates a seamless transfer of responsibilities from the development team through construction to commercial operations in order to ensure all contractual and regulatory obligations are clearly captured and tracked in a formal compliance program.
- Environmental Management and Community Relations. Adaptive environmental management is increasingly the standard by which power projects are managed. Our company has been a leader in adopting strategies to minimize environmental impacts, such as bird and bat fatalities. Each project has different circumstances so our environmental and community programs range from hiring of local personnel and historical preservation to use of advanced radar systems to monitor birds and bats and presence of on-site biologists to assist in species recognition and mitigation management. By proactively addressing the concerns of the regions, our environmental management and community relations programs seek to minimize additional costs and burdens from a potential increase in regulations or law suits.
- Power Marketing. A crucial element of a successful project is assuring revenue from the sale of power and other environmental attributes. We manage the risk associated with fluctuations in electricity prices across our business by seeking to commit the electricity we generate under long-term, fixed-price power sale agreements. Our uncontracted power and renewable attributes are sold in the spot-market or under shorter term contracts to optimize revenue realization. We believe this management philosophy will result in a steady, predictable source of revenue for each of our projects.
- Finance. Our projects are typically funded with construction financing during the construction phase which converts to long-term financing when the project commences commercial operations. Debt at each individual project is project financed, which means that, with very limited exceptions, the lenders have no or only limited recourse to other assets of the company other than the assets that are being financed. Debt for our projects is typically provided by commercial banks and institutional lenders that have the expertise to evaluate the risks associated with the construction and operation of a wind power project, including evaluation of the equipment technology, construction, operations and wind resources. These lenders provide construction financing for many sizable industrial and infrastructure projects. Since debt comprises a significant portion of total project capitalization, achievement of construction financing is a general indication that lenders and their independent consultants have carefully evaluated the project and find it viable for long-term financing. Given the complexity involved in financing large infrastructure assets, projects are often completed with a syndicate of lenders, and the credibility we have established among the

financial community allows lenders to have confidence in the quality of our projects and enables us to secure competitive financing terms and other financing efficiencies for our projects. Over the years, our team has developed close relationships with many of the active renewable energy lenders.

Engineering and Construction

The key leadership in our engineering and construction group resides within our company, which provides us with the in-house capabilities required to evaluate and manage a project’s design and construction processes. We will rely as necessary upon additional personnel from third-party sources and Pattern Development with respect to the construction of our projects. We also typically enter into fixed-price construction contracts for our projects' with a guaranteed completion date to encourage completion on time and within budget.

Project design involves close and frequent communication with both field development personnel as well as the construction contractor in order to develop a project that conforms to local geotechnical and topographic characteristics while accommodating permitting and real estate restrictions. Pattern Development also strives to integrate experience obtained from operating projects in order to design projects with optimal maintenance and equipment-availability profiles. During construction, we are responsible for overseeing the construction contractor and turbine-vendor activities to ensure that the construction schedule is met. Collaboration among engineers and managers on each of our projects and our major equipment suppliers allows us to efficiently transition from construction to commercial operations and to identify and process technical improvements over the life-cycle of each project.

Our engineering and construction team is comprised of highly experienced project and construction managers and includes personnel who have supervised the design and on budget completion of construction of 35 wind power projects over the last 13 years. We set, and ensure compliance with, design specifications and take an active role in supervising field work, safety compliance, quality control and adherence to project schedules. Each project has a dedicated resident construction manager, and other engineering and construction functions are centralized, which allows the group to efficiently scale its resources to support our developing global platform and growth strategy.

Investing

We are organized in a manner that will allow us to independently and comprehensively evaluate investments in new projects. Key members of our management team, including Messrs. Garland, Armistead, Elkort, Lyon, and Pedersen, have spent extensive periods of their careers in the investment advisory, principal investment and finance fields.

As a major part of our growth strategy, we intend to seek to acquire projects that would contribute measurable amounts to our cash available for distribution and adjusted EBITDA. Our approach to project selection is focused on projects (i) with strong economics that will support our long-term financial goals, as determined by intensive analysis and in-depth due diligence, (ii) in which we can add value and which have characteristics that are strategically compatible with our other projects and overall business, and (iii) which meet our core values, including our commitments to environmental stewardship and being a good neighbor in the communities in which our projects are located. To achieve proper investment management, we have implemented processes to ensure rigorous analysis and proper internal approval controls, including preparing formal investment approval documentation, maintaining strict limits on delegation of authority for making capital commitments, and vetting our assumptions with independent technical experts and advisors.

Competition

We compete with other wind power, infrastructure funds and renewable energy companies, as well as conventional power companies, to acquire profitable construction-ready and operating projects. In addition, competitive conditions may be substantially affected by various forms of energy legislation and regulation considered from time to time by federal, state, provincial and local legislatures and administrative agencies.

Suppliers

There are a limited number of turbine suppliers and, although demand for turbines in the past has generally been high relative to manufacturing capacity, we believe that current turbine manufacturing capacity is adequate. Our turbine supply strategy is largely based on maintaining strong relationships with leading turbine suppliers to secure our supply needs.

Project	Supplier	Number of Turbines	Turbine Type
Operating Projects			
Gulf Wind	Mitsubishi	118	MWT 95/2.4
Hatchet Ridge	Siemens	44	SWT-2.3-93
St. Joseph	Siemens	60	SWT-2.3-101
Spring Valley	Siemens	66	SWT-2.3-101
Santa Isabel	Siemens	44	SWT-2.3-108
Ocotillo	Siemens	112	SWT-2.3-108
South Kent	Siemens	124	SWT-2.3-101
El Arrayán	Siemens	50	SWT-2.3-101
Panhandle 1	General Electric	118	1.85 - 87
Panhandle 2	Siemens	79	SWT-2.3-108
Grand	Siemens	67	SWT-2.3-101
Post Rock	General Electric	134	1.5-82.5
Lost Creek	General Electric	100	1.5-82.5
K2	Siemens	140	SWT-2.3-101
Logan’s Gap	Siemens	87	SWT-2.3-108
Amazon Wind Farm Fowler Ridge	Siemens	65	SWT-2.3-108

To date, our projects listed above have purchased 938 turbines from Siemens. Siemens data indicates that worldwide fleet availability for the 2.3MW turbine class exceeds 97%, and our Siemens fleet availability also exceeded 97% in 2015. Apart from Siemens we have relationships with other reputable turbine manufacturers such as General Electric and Mitsubishi. Some of our future projects may utilize turbines from these and other manufacturers.

Our Ocotillo and Santa Isabel (Siemens) and Gulf Wind (MHI) projects have experienced certain blade failures in the last three years. We believe the Siemens blade failures have been fully addressed through the completion of an agreed inspection and repair program. With respect to MHI, we worked with MHI to complete a root cause analysis, testing of the blades at the Gulf Wind facility, and development of a protocol for determining whether a blade might pose a threat to long-term reliable operation. We reached in November 2015 a long term arrangement with MHI to address potential deficiencies and, if applicable, mitigation for lost revenue resulting from blade downtime at the facility. We believe that this agreement and mitigation strategy provide adequate technical and commercial protections to the project to mitigate the impacts of this issue, but can give no assurance that additional issues will not arise for which these measures prove inadequate.

Other important suppliers include engineering and construction companies, such as M. A. Mortenson Company, RES-Americas and Blattner Energy, Inc., with whom we contract to perform civil engineering, electrical work and other infrastructure construction for our projects.

We currently depend on service providers to provide maintenance services to our project equipment. These services are currently provided by the turbine manufacturers, such as Siemens or General Electric, at most of our project sites. We believe there are currently adequate independent service provider alternatives to the turbine manufacturers to meet our needs, and in some cases we do utilize such alternative providers.

Customers

We sell our electricity and RECs, primarily to local utilities under long-term, fixed-price PPAs or, in limited instances, local liquid ISO markets. For the year ended December 31, 2015, the significant customer representing greater than 10% of total revenue was San Diego Gas & Electric ("SDG&E"), which accounted for 17% of our total revenue.

From time to time, we enter into hedges to manage our business exposure to commodity, foreign exchange rate and interest rate risks. In doing so, our hedging strategy is generally focused on reducing potential changes to key business drivers such as power prices, interest rates and changes in income from overseas investments.
Most of our revenue is subject to long-term PPAs. To the extent that PPAs are not available in a given market, but market prices allow for acceptable project economics, we will enter into hedging agreements to obtain a fixed price for the energy output of our projects, typically by hedging volumes that are expected to be exceeded 99.0% of the time. Those hedging agreements are executed for a monthly or hourly production profile that matches the forecasted production profile of the project. On an overnight basis, we will also consider hedging agreements beyond the initial volume up to an amount that is expected to be exceeded over half the time.
Most of our interest rate exposure is hedged either through fixed-rate debt arrangements or hedging of floating rate loans. We enter into interest rate hedging agreements to convert floating-rate debt to fixed-rate debt for some of our projects, usually at the time we close construction or term financing of a project. We also monitor our corporate-level interest rate exposure and may, from time to time, enter into interest rate hedges in order to mitigate our exposure.
In 2015, we initiated a program of exchange rate management due to the substantial portion of our electricity sales that are Canadian dollar denominated. For additional information regarding our hedging activities, see Item 7A "Quantitative and Qualitative Disclosure about Market Risk."

Structure of Our Company

(1) These funds and these employees hold indirect interests in Pattern Development.

(2) Subsequent to our issuance of shares and the sale of certain of our shares held by Pattern Development during 2015, Pattern Development's ownership interest in us was reduced to approximately 23%, while public and management ownership increased to approximately 77%.

Employees

As of December 31, 2015, we had 116 full-time employees of whom 32 are based in our corporate headquarters, 46 are based at our project sites and 38 are based at our other offices, including our OCC, in Houston, Texas. None of our employees are represented by a labor union or covered by any collective bargaining agreement.

Insurance

We maintain insurance on terms generally carried by companies engaged in similar business and owning similar properties in the United States, Canada and Chile and whose projects are financed in a manner similar to our projects. As is common in the wind industry, however, we do not insure fully against all the risks associated with our business either because insurance is not available or because the premiums for some coverage are prohibitive. For example, we do not maintain war risk insurance. We maintain varying levels of insurance for the development, construction, and operation phases of our projects, including property insurance, which, depending on the location of each project, may include catastrophic windstorm, flood, and earthquake coverage (CAT coverage); transportation insurance; advance loss of profits insurance; business interruption insurance; general liability and umbrella liability insurance; time element pollution liability insurance; auto liability insurance; workers' compensation and employer's liability insurance; and (except in Chile) title insurance. The "all risk" property insurance coverage is currently maintained in amounts based on the full replacement value of our projects (subject to certain sub-limits for windstorm, flood, and earthquake risks) and the business interruption insurance generally provides 15 months of coverage in amounts that vary from project to project based on the revenue generation potential of each project. All types of coverage are subject to applicable deductibles. We generally do not maintain insurance for certain environmental risks, such as environmental contamination.

Industry

Wind power has been one of the fastest growing sources of electricity generation in North America and globally over the past decade. According to the Global Wind Energy Council, or "GWEC," from 2001 through 2013, total net electricity generation from wind power in the United States and Canada grew at a combined annual growth rate of 27% and 37%, respectively. The growth in the industry is largely attributable to renewable energy's increasing cost competitiveness with other power generation technologies, the advantages of wind power over other renewable energy sources, and growing public support for renewable energy driven by energy security and environmental concerns. As global demand for electricity generation from wind power has increased, technology enhancements-supported by U.S. government incentives-have reduced the cost of wind power by more than 80% over the last twenty years, according to the American Wind Energy Association, or "AWEA."

The United States is the largest producer of wind power in the world. According to AWEA, wind power was the largest source of new electricity generating capacity in the U.S. in 2015, accounting for more than 35% of new generation. Wind power was the first or second largest source of new generating capacity in the United States for seven of the eight years between 2005 and 2012, according to the U.S Department of Energy and AWEA. According to AWEA, wind power became the leading source of new electricity generating capacity in the United States for the first time in 2012. The American wind energy industry installed 8,598 MW in 2015 and 4,854 MW in 2014 and the U.S. now has an installed wind capacity of 74,472 MW with over 9,400 MW of wind currently under construction across 22 states. The success of wind power in the United States is evidenced by over $120.0 billion in investments to date, according to AWEA.

Renewable energy sources in the United States have benefited from various federal and state governmental incentives, such as production tax credits and investment tax credits. Production tax credits and investment tax credits for wind energy on the federal level were extended in December of 2015, under the Consolidated Appropriations Act. The Act extended the expiration date for tax credits for wind facilities commencing construction, with a five year phase-down beginning for wind projects commencing construction after December 31, 2016. The Act also applies retroactively to January 1, 2015. In addition to an extension of the production tax credits, in August 2015, President Obama and the Environmental Protection Agency announced the Clean Power Plan, or "CPP," a key step in reducing carbon pollution from power plants which is designed to strengthen the fast-growing trend toward cleaner and lower-emitting power plants. The CPP is expected to reduce carbon dioxide emissions from power plants to 32% below 2005 levels by 2030.

For each state, the CPP rules will establish a target emissions rate, or the amount of carbon dioxide that could be emitted per megawatt-hour of power produced and states are expected to start working toward interim emissions goals beginning in 2022. Depending on how the rule is implemented, it could drive demand for up to 100 GW of new wind energy by 2030 according to AWEA. However, in February 2016, the U.S. Supreme Court issued a stay prohibiting the implementation of the CPP pending a challenge to the CPP before a U.S. Court of Appeals.

The Canadian wind power industry has also experienced dramatic growth in recent years. Canada gained 1,505 MW in 2015, and 1,416 MW in 2014 of new installed wind power generating capacity. This investment resulted in wind power generating capacity in Canada reaching approximately 11,205 MW as of December 2015. According to the Canadian Wind Energy Association, or

"CanWEA," new installed wind power generating capacity is expected to average 1,500 MW annually over the next three years. Ontario, one of our markets, is the national leader in installed capacity, with approximately 4.4 GW of wind power generating capacity at the close of 2015, although recent changes to the Ontario government feed-in tariff, or "FIT," regime may make future projects less attractive and power purchase agreements more difficult to obtain. CanWEA forecasts total wind power generating capacity in Canada to exceed 12 GW at the end of 2016.

Chile, also one of our markets, has an abundant wind resource, which GWEC estimates could provide the potential for more than 40 GW of generating capacity. 2014 was a strong year for Chilean wind development, with the country's new installed capacity reaching 506 MW, which is nearly four times the previous record of 130 MW set in 2013, according to the state-run Renewable Energy Centre. That brought the country's total wind power capacity to 836 MW. Wind now supplies approximately 2% of the country's electricity demand.

In June 2015, we added three Japanese wind projects and two Japanese solar projects to our list of Identified ROFO Projects. Following the nuclear meltdown at the Fukushima Daiichi plant in 2011, the Japanese government has placed a greater emphasis on the development of renewable resources in order to reduce its reliance on nuclear power, having released its Innovative Strategy for Energy and the Environment in September 2012. By 2030, the plan calls for renewable power generation to triple compared to 2010, reaching about 30% of total generation. In 2012, Japan also introduced a FIT program that offers fixed-term, fixed-price contracts (up to 20 years) to renewable power projects. The tariff will be re-assessed every year based on the latest market experience in Japan. At the end of 2014, 2,789 MW of wind capacity was operating in Japan. This accounted for approximately 1% of the total power supply in 2014.

Although the Company does not yet have assets or Identified ROFO Projects in Mexico, it is a key potential market for us as Pattern Development is actively working in the country and we expect to add Mexican projects to the Identified ROFO Projects list in the future. Mexico's Congress has enacted sweeping reforms to its electric generation industry in recent years, opening new opportunities for private investment in generation and creating a mandate to obtain at least 35% of its generation from clean sources by 2024. High prices and strong load growth were key factors in encouraging the reforms, and Mexico's SENER (Secretaria de Energia) has published rules for interconnection and a new market-oriented regime. Mexico has substantial wind and solar resources, and thus far has only developed less than two thousand megawatts of wind generation under the pre-reform system. It is anticipated by the Mexican Wind Energy Association (Asociación Mexicana de Energía Eólica) that several thousand megawatts of wind generation will be developed over the next few years. During 2014, Mexico added 634 MW of new wind power to the country's electricity grid bringing the total capacity to 2,551 MW.

Given supply diversity requirements, falling equipment costs, the inherent stability of the cost of wind power as an energy resource and an active market for the purchase and sale of power projects, we believe that our markets present a substantial opportunity for growth. We require a relatively small share of a very large market to meet our growth objectives and we believe we will achieve growth through the acquisition of operational and construction-ready projects from Pattern Development and other third parties.

While we currently operate primarily in wind power markets, we expect to continue to evaluate other types of independent power projects for possible acquisition, including renewable energy projects other than wind power projects and non-renewable energy projects. In September 2014, we announced the addition of our first solar project, the 104 MW Conejo Solar photovoltaic power project in Chile, to our list of Identified ROFO, and in June 2015, we added two Japanese solar projects to that list.

Regulatory Matters

Environmental Regulation

We are subject to various environmental, health and safety laws and regulations in each of the jurisdictions in which we operate. These laws and regulations require us to obtain and maintain permits and approvals, undergo environmental review processes and implement environmental, health and safety programs and procedures to monitor and control risks associated with the siting, construction, operation and decommissioning of wind power projects, all of which involve a significant investment of time and can be expensive.

We incur costs in the ordinary course of business to comply with these laws, regulations and permit requirements. We do not anticipate material unplanned capital expenditures for environmental controls for our operating projects in the next several years. However, these laws and regulations frequently change and often become more stringent, or subject to more stringent interpretation or enforcement. Future changes could require us to incur materially higher costs.

Failure to comply with these laws, regulations and permit requirements may result in administrative, civil and criminal penalties, imposition of investigatory, cleanup and site restoration costs and liens, denial or revocation of permits or other authorizations and issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property or for injunctive relief have been brought and may in the future result from environmental and other impacts of our activities.

Environmental Permitting—United States

We are required to obtain from U.S. federal, state and local governmental authorities a range of environmental permits and other approvals to build and operate our projects, including, but not limited to, those described below. In addition to being subject to these regulatory requirements, we could experience and have experienced significant opposition from third parties when we initially apply for permits or when there is an appeal proceeding after permits are issued. The delay or denial of a permit or the imposition of conditions that are costly or difficult to comply with can impair or even prevent the development of a project or can increase the cost so substantially that the project is no longer attractive to us.

Federal Clean Water Act

Frequently, our U.S. projects are located near wetlands, and we are required to obtain permits under the U.S. Clean Water Act from the U.S. Army Corps of Engineers, or the "Army Corps," for the discharge of dredged or fill material into waters of the United States, including wetlands and streams. The Army Corps may also require us to mitigate any loss of wetland functions and values that accompanies our activities. In addition, we are required to obtain permits under the Clean Water Act for water discharges, such as storm water runoff associated with construction activities, and to follow a variety of best management practices to ensure that water quality is protected and impacts are minimized. Certain activities, such as installing a power line across a navigable river, may also require permits under the Rivers and Harbors Appropriation Act of 1899.

Federal Bureau of Land Management Permits

As some of our U.S. projects are located on lands administered by the Bureau of Land Management, we are required to obtain rights-of-way from the Bureau of Land Management. The Bureau of Land Management encourages the development of wind power within acceptable areas, consistent with Environmental Policy Act of 2005 and the Bureau of Land Management’s energy and mineral policy. Obtaining a grant requires that the proposed project prepare a plan of development and demonstrate that it will adhere to the Bureau of Land Management’s best management practices for wind power development, including meeting criteria for protecting biological, archaeological and cultural resources.

National Environmental Policy Act and Endangered Species Requirements

Our U.S. projects may also be subject to environmental review under the U.S. National Environmental Policy Act, or "NEPA," which requires federal agencies to evaluate the environmental impact of all "major federal actions" significantly affecting the quality of the human environment. The granting of a land lease, a federal permit or similar authorization for a major development project, or the interconnection of a significant private project into a federal project generally is considered a "major federal action" that requires review under NEPA. As part of the NEPA review, the federal agency considers a broad array of environmental impacts, including impacts on air quality, water quality, wildlife, historical and archaeological resources, geology, socioeconomics and aesthetics and alternatives to the project. The NEPA review process, especially if it involves preparing a full Environmental Impact Statement, can be time-consuming and expensive. A federal agency may decide to deny a permit based on its environmental review under NEPA, though in most cases a project would be redesigned to reduce impacts or agree to provide some form of mitigation to offset impacts before a denial is issued.

Federal agencies granting permits for our U.S. projects also consider the impact on endangered and threatened species and their habitat under the U.S. Endangered Species Act, which prohibits and imposes stringent penalties for harming endangered or threatened species and their habitats. Our projects also need to consider the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act, which protect migratory birds and bald and golden eagles and are administered by the U.S. Fish and Wildlife Service. Most states also have similar laws. Because the operation of wind turbines may result in injury or fatalities to birds and bats, federal and state agencies often recommend or require that we conduct avian and bat risk assessments prior to issuing permits for our projects. They may also require ongoing monitoring or mitigation activities as a condition to approving a project. In addition, U.S. federal agencies consider a project’s impact on historical or archeological resources under the U.S. National Historic Preservation Act and may require us to conduct archeological surveys or take other measures to protect these resources. Among other things, the National Historic Preservation Act requires federal agencies to evaluate the impact of all federally funded or permitted projects on historic properties (buildings, archaeological sites, etc.) through a process known as "Section 106 Review."

Other State and Local Programs

In addition to federal requirements, our U.S. projects, and any future U.S. projects we may acquire, are subject to a variety of state environmental review and permitting requirements. Many states where our projects are located, or may in the future be located, have laws that require state agencies to evaluate a broad array of environmental impacts before granting state permits. The state environmental review process often resembles the federal NEPA process and may be more stringent than the federal review. Our projects also often require state law based permits in addition to federal permits. State agencies evaluate similar issues as federal agencies, including the project's impact on wildlife, historic sites, aesthetics, wetlands and water resources, agricultural operations and scenic areas. States may impose different or additional monitoring or mitigation requirements than federal agencies. Additional approvals may be required for specific aspects of a project, such as stream or wetland crossings, impacts to designated significant wildlife habitats, storm water management and highway department authorizations for oversize loads and state road closings during construction. Permitting requirements related to transmission lines may be required in certain cases.

Our projects also are subject to local environmental and regulatory requirements, including county and municipal land use, zoning, building and transportation requirements. Permitting at the local municipal or county level often consists of obtaining a special use or conditional use permit under a land use ordinance or code, or, in some cases, rezoning in connection with the project. Obtaining a permit usually depends on our demonstrating that the project will conform to development standards specified under the ordinance so that the project is compatible with existing land uses and protects natural and human environments. Local or state regulatory agencies may require modeling and measurement of permissible sound levels in connection with the permitting and approval of our projects. Local or state agencies also may require us to develop decommissioning plans for dismantling the project at the end of its functional life and establish financial assurances for carrying out the decommissioning plan.

Environmental Permitting—Canada

We are required to obtain from Canadian federal, provincial and local governmental authorities a range of environmental permits and other approvals to build and operate our Canadian projects, including, but not limited to, those described below. In addition to being subject to these regulatory requirements, we could experience and have experienced significant opposition from third parties, including, but not limited to, environmental non-governmental organizations, neighborhood groups, municipalities and First Nations when the permits were initially applied for or when there is an appeal proceeding after permits are issued. The delay or denial of a permit or the imposition of conditions that are costly or difficult to comply with can impair or even prevent the development of a project or can increase the cost so substantially that the project is no longer attractive to us.

Ontario Renewable Energy Approvals

Our projects in Ontario are subject to Ontario's Environmental Protection Act, which requires proponents of significant renewable energy projects to obtain a Renewable Energy Approval, or "REA." The REA application requires a variety of studies on environmental, archeological and heritage issues. Significant public consultation, as well as consultation with indigenous communities, is also required. Before issuing a REA, the Ontario Ministry of the Environment evaluates a broad range of potential impacts, including on wildlife, wetlands and water resources, communities, scenic areas, species and heritage resources, as well as impacts on people. This review can be time consuming and expensive, and an approval can be rejected or approved with conditions that are costly or difficult to comply with. REAs are also subject to appeal by third parties and can result and have resulted in lengthy appeal tribunal hearings.

The Henvey Inlet Wind Identified ROFO Project is located within Henvey Inlet Reserve No. 2, a reserve held by Her Majesty the Queen in right of Canada for the benefit of Henvey Inlet First Nation, and since the REA process is not directly applicable to Reserve lands, the project will be subject to an environmental assessment and protection regime adopted and enforced by the Henvey Inlet First Nation, acting through its elected Band Council. The Band Council has legal authority to enact and enforce land laws, including this regime, pursuant to relevant codes, acts, agreements and legislation. The foregoing legal regime provides Henvey Inlet First Nation with control and management of the Reserve for the purposes of the enactment of the applicable environmental regime, and the granting of a lease of portions of the Reserve for the purposes of the project. The risks and obligations of the foregoing permitting and enforcement regime are similar in substance to those which exist under the REA process.

Quebec Environmental Impact Assessment

Our Identified ROFO Project in Quebec (Mont Sainte-Marguerite) is subject to Quebec`s Environmental Impact Assessment, or "EIA," which is a required permit for wind energy projects with a nameplate capacity above 10 MW. The EIA requires a variety of studies related to environmental, archeological and heritage issues. Significant public consultation, as well as consultation with indigenous communities, is also required. The culmination of this permitting process is the issuing of a project specific decree by the provincial council of ministers. Before issuing the decree, the Quebec Ministry of Environment evaluates a broad range of potential impacts, including on wildlife, wetlands and water resources, communities, scenic areas, species and heritage resources, as well as impacts on people. Within the EIA process, there is the possibility that a formal public hearing takes place. This public hearing is conducted by an independent commission called the BAPE (Public Audience Bureau on the Environment). This hearing can be triggered by private citizens, public interest groups, or any other interested parties. The BAPE hearing will add four additional months to the permitting schedule. For large industrial projects, the calling of this hearing is the norm.

Quebec Commission for the Protection of Agricultural Land

In addition to the EIA process, the other major permit in Quebec is granted by the Quebec Commission for the Protection of Agricultural Land, or "CPTAQ." This permit is only required on land that is zoned agricultural. This encompasses traditional grain farming land, as well as commercial forestry land. This permitting body will push proponents to minimize footprints during both the construction phase and the operations phase. The CPTAQ is an independent commission from the agricultural ministry.

Manitoba Environment Act

The Manitoba Environment Act requires proponents of significant projects to submit a proposal with the Manitoba Conservation Environmental Assessment & Licensing Branch, and to comply with Manitoba's environmental assessment process under the Environment Act. This process will consider a similar range of impacts on the environment, the heritage and scenic values of an area and on people, communities and wildlife as the Ontario process, and brings with it similar risks.

Endangered Species Legislation

Our Canadian renewable energy projects may be subject to endangered species legislation, either federally or provincially, which prohibits and imposes stringent penalties for harming endangered or threatened species and their habitats. Our projects may also be subject to the Migratory Birds Convention Act, which protects the habitat of migratory species, and which may also trigger federal "Species at Risk" requirements. Because the operation of wind turbines may result in injury or fatalities to birds and bats, avian and bat risk assessments are generally required both prior to permits being issued for projects and after commercial operations. In Ontario, if any of the affected species are listed as endangered or threatened, permits under the Endangered Species Act may also be required.

Other Approvals

Our Canadian projects, and any future projects we may acquire, are subject to a variety of other federal, provincial and municipal permitting and zoning requirements. Most provinces where our projects are located or may be located have laws that require provincial agencies to evaluate a broad array of environmental impacts before granting permits and approvals. These agencies evaluate similar issues as the permitting regimes above, including impact on wildlife, historic sites, esthetics, wetlands and water resources, scenic areas, endangered and threatened species and communities. In addition, federal government approvals dealing with, among other things, aeronautics, fisheries, navigation or species protection may be required and could in some cases trigger additional environmental assessment requirements. Additional requirements related to the permitting of transmission lands may be applicable in some cases. Our projects are also subject to certain municipal requirements, including land use and zoning requirements except where superseded by Ontario's Green Energy and Green Economy Act, 2009, as well as requirements for building permits and other municipal approvals that can be difficult or costly to comply with and impair or prevent the development of a project.

Environmental Permitting – Chile

Ministry of Environment, Environmental Assessment Service and Superintendency of Environment

The Ministry of the Environment, the Environmental Assessment Service and the Superintendency of Environment are primarily responsible for environmental issues in Chile, including those affecting the wind industry. The Ministry of the Environment is responsible for the formulation and implementation of environmental policies, plans and programs, as well as for the formulation of environmental quality and emission standards, the protection and conservation of biological diversity, renewable natural resources and water resources, and for promoting sustainable development and the integrity of environmental policy and regulations. The Environmental Assessment Service is responsible for assessing whether projects that might have an adverse effect on the environment, including wind projects, comply with Chilean environmental laws and regulations. The Environmental Assessment Service coordinates the environmental impact assessment process, whose final qualifications are granted by the competent regional Environmental Assessment Commission. The Superintendency of the Environment's primary responsibilities are monitoring compliance with the terms of the corresponding environmental licenses, as well as monitoring compliance with government plans to prevent environmental damage or to clean or restore contaminated geographical areas. The Superintendency of the Environment has the power to suspend activities that it deems to have an adverse environmental impact, even if such activities comply with a previously approved environmental impact assessment. In case of noncompliance with environmental regulations, it is enabled to apply fines, revoke the environmental license of a project or determine its closure.

The Environmental Courts, and Health and Safety

The Environmental Courts are principally responsible for hearing appeals of determinations made by the Superintendency of the Environment and for adjudicating claims for environmental damage.

Companies in the wind energy sector, like all companies, must comply with the general principles concerning employee health and safety contained in the Chilean Sanitary Code, Labor Code and other labor and health regulations. The Chilean Health Ministry and the Department of Labor are responsible for the enforcement of those standards, with the authority to impose fines among other sanctions. In addition, the Superintendence of Electricity and Fuels has the responsibility to monitor compliance and also the authority to impose fines and stop operations of violators.

Management, Disposal and Remediation of Hazardous Substances

We own and lease real property and may be subject to requirements regarding the storage, use and disposal of petroleum products and hazardous substances, including spill prevention, control and counter-measure requirements. If our owned or leased properties are contaminated, whether during or prior to our ownership or operation, we could be responsible for the costs of investigation and cleanup and for any related liabilities, including claims for damage to property, persons or natural resources. That responsibility may arise even if we were not at fault and did not cause or were not aware of the contamination. In addition, waste we generate is at times sent to third-party disposal facilities. If those facilities become contaminated, we and any other persons who arranged for the disposal or treatment of hazardous substances at those sites may be jointly and severally responsible for the costs of investigation and remediation, as well as for any claims for damage to third parties, their property or natural resources.

Intellectual Property

In September 2014, we exercised our right to acquire the name "Pattern" and the Pattern logo from Pattern Development, and granted to Pattern Development a license to use the name "Pattern" and the Pattern logo. We have registrations and pending applications for registration of marks in the United States, Canada and Chile. We do not own any intellectual property material to the conduct of our business. We also own various information that includes, without limitation, financial, business, scientific, technical, economic, engineering information, formulas, designs, methods, techniques, processes, and procedures, all of which is protected confidential and proprietary information.

Geographic information

The table below provides information about our consolidated operations by country. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located (in thousands):

	Revenue			Property, Plant and Equipment, net (including Construction in Progress)		
	Year ended December 31,			December 31,		
	2015	2014	2013	2015	2014	2013
United States	$258,542	$201,408	$161,505	$2,791,259	$1,810,414	$1,210,319
Canada	39,178	46,593	40,068	184,115	233,690	265,823
Chile	32,111	17,492	—	319,246	332,947	—
Total	$329,831	$265,493	$201,573	$3,294,620	$2,377,051	$1,476,142

Available Information

Periodic reports for the Company on Form 10-K and Form 10-Q and current reports on Form 8-K are made available to the public, free of charge, on the Company's website (www.patternenergy.com) through links on this website to the SEC’s website at www.sec.gov, as soon as reasonably practicable after they have been filed with the SEC. The contents of the above referenced website address are not part of this Form 10-K. The public may also read any copy of materials filed with the SEC by the Company at the SEC’s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the

Public Reference Room may be obtained by calling the SEC at 1-(800) SEC-0030. Reports, proxy and information statements, and other information regarding the Company may also be obtained directly from the SEC's website, www.sec.gov. Printed copies of these documents may be obtained free of charge by writing to the Company's Corporate Secretary at Pattern Energy Group Inc., Pier 1, Bay 3, San Francisco, CA 94111.

Item 1A. Risk Factors.

RISK FACTORS

You should carefully consider the following risks, together with other information provided to you in this Form 10-K. If any of the following risks were to occur, our business, financial condition, results of operations and liquidity could be materially adversely affected. In that case, we might have to decrease, or may not be able to pay, dividends on our Class A shares, the trading price of our Class A shares could decline and you could lose all or part of your investment. The risks described below are not the only risks facing our company. Risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and results of operations and liquidity.

Risks Related to Our Projects

Electricity generated from wind energy depends heavily on suitable wind conditions and wind turbines being available for operation. If wind conditions are unfavorable or below our expectations, or our wind turbines are not available for operation, our projects' electricity generation and the revenue generated from our projects may be substantially below our expectations.

The revenue generated by our projects is principally dependent on the number of MWh generated in a given time period. The quantity of electricity generation from a wind power project depends heavily on wind conditions, which are variable. Variability in wind conditions can cause our project revenues to vary significantly from period to period. We base our decisions about which projects to acquire as well as our electricity generation estimates, in part, on the findings of long-term wind and other meteorological studies conducted on the project site and its region, which measure the wind's speed, prevailing direction and seasonal variations. Projections of wind resources also rely upon assumptions about turbine placement, wind turbine power curves, interference between turbines and the effects of vegetation, land use and terrain, which involve uncertainty and require us to exercise considerable judgment. We may make incorrect assumptions in conducting these wind and other meteorological studies. Any of these factors could cause our projects to generate less electricity than we expect and reduce our revenue from electricity sales, which could have a material adverse effect on our business, financial condition and results of operations.

Even if an operating project's historical wind resources are consistent with our long-term estimates, the unpredictable nature of wind conditions often results in daily, monthly and yearly material deviations from the average wind resources we may anticipate during a particular period. If the wind resources at a project are materially below the average levels we expect for a particular period, our revenue from electricity sales from the project could correspondingly be less than expected. For example, according to Vaisala, a globally-recognized environmental measurement company with meteorological expertise, average wind conditions across the western United States and Texas were 20% or more below normal for the first quarter of 2015. The low production was primarily the result of unusual weather conditions brought on by particular features of an El Niño weather pattern over the Pacific Ocean. Vaisala stated at the time that the observed weather pattern was nothing unusual or outside of the range of the expected after their review of long term global datasets. The El Niño weather pattern strengthened through 2015, became one of the strongest observed, and had varying effects on our fleet level production during the year based on season. No assurances can be given that there will not continue to be material deviations from average wind resources. A diversified portfolio of projects located in different geographical areas tends to reduce the magnitude of the deviation, but material deviations may still occur. Our cash available for distribution is most directly affected by the volume of electricity generated and sold by our projects. However, for a static portfolio of projects, our consolidated expenses, including operating expenses and interest payments on indebtedness, have less variability than the volume of electricity generated and sold. Accordingly, decreases in the volume of electricity generated and sold by our projects typically result in a proportionately greater decrease in our cash available for distribution. See Item 7

"Management's Discussion and Analysis of Financial Condition and Results of Operation-Factors that Significantly Affect our Business-Factors Affecting our Operational Results-Electricity Sales and Energy Derivative Settlements of Our Operating Project."

A reduction in electricity generation and sales, whether due to the inaccuracy of wind energy assessments or otherwise, could lead to a number of material adverse consequences for our business, including:

- our projects' failure to produce sufficient electricity to meet our commitments under our PPAs, hedge arrangements or contracts for sale of RECs, which could result in our having to purchase electricity or RECs on the open market to cover our obligations or result in the payment of damages or the termination of a PPA;

- our projects not generating sufficient cash flow to make payments of principal and interest as they become due on project-related debt, or distributing sufficient cash flow to pay dividends to holders of our Class A shares. See "-Risks Related to Ownership of our Class A Shares - Our cash available for distribution to holders of our Class A shares may be reduced as a result of restrictions on our subsidiaries' cash distributions to us under the terms of their indebtedness;" and
- our projects' hedging arrangements being ineffective or more costly.

Our projects rely on a limited number of key power purchasers. The power purchaser for our Santa Isabel project has been downgraded.

There are a limited number of possible power purchasers for electricity and RECs produced in a given geographic location. Because our projects depend on sales of electricity and RECs to certain key power purchasers, our projects are highly dependent upon these power purchasers fulfilling their contractual obligations under their respective PPAs. Our projects' power purchasers may not comply with their contractual payment obligations or may become subject to insolvency or liquidation proceedings during the term of the relevant contracts and, in such event, we may not be able to find another purchaser on similar or favorable terms or at all. In addition, we are exposed to the creditworthiness of our power purchasers and there is no guarantee that any power purchaser will maintain its credit rating, if any. To the extent that any of our projects' power purchasers are, or are controlled by, governmental entities, our projects may also be subject to legislative or other political action that impairs their contractual performance. Failure by any key power purchasers to meet its contractual commitments or the insolvency or liquidation of one or more of our power purchasers could have a material adverse effect on our business, financial condition and results of operations.

For example, our 101 MW Santa Isabel project located on the south coast of Puerto Rico sells 100% of its electricity generation including environmental attributes to PREPA under a 20-year PPA. PREPA's credit rating was downgraded multiple times in each of 2014 and 2015. As of February 24, 2016, the credit rating of PREPA was Caa3, CC, and CC by each of Moody's, Standard & Poor's, and Fitch, respectively, which ratings are all below investment grade. In addition, in June 2014, Puerto Rico enacted legislation to establish a bankruptcy-like regime for public corporations in Puerto Rico, like PREPA, which were ineligible for relief under U.S. federal bankruptcy laws, to restructure their debt and other obligations. The validity of such legislation was challenged in U.S. federal court, and in 2015 the court declared such legislation unconstitutional, which decision was later confirmed by an appeals court. The Commonwealth of Puerto Rico sought review before the U.S. Supreme Court which agreed to hear the case, and oral argument is expected to take place around March 2016. PREPA has hired a chief restructuring officer to produce a restructuring plan, and entered into a forbearance agreement and multiple extensions with certain of its creditors. PREPA has entered into a restructuring support agreement with certain lenders, bondholders and other parties which would implement a plan that would reduce PREPA's principal debt burden and provide debt service relief for five years. Legislation called for under the agreement and essential to the successful execution of the plan was approved by the Puerto Rico legislature and enacted into law on February 16, 2016. The final version of the statute approved by the legislature is currently under review by PREPA's creditors. While as of February 29, 2016, PREPA is current with respect to payments due under the PPA, a failure by PREPA to perform its payment obligations under the PPA, a restructuring of its obligations under judicially determined valid legislation, or a failure to consummate the restructuring support agreement may affect its obligations under the PPA which could have a material adverse effect on our business, financial condition and results of operations.

A prolonged environment of low prices for natural gas, other conventional fuel sources, or competing renewable resources could have a material adverse effect on our long-term business prospects, financial condition and results of operations.

Historically low prices for traditional fossil fuels, particularly natural gas, could cause demand for wind power and solar power to decrease and adversely affect both the price available to us under power sale agreements that we may enter into in the future and the price of the electricity we generate for sale on a spot-market basis. Approximately 11% of the electricity generated from our projects will be subject to spot-market pricing through at least April 2019. Low spot-market power prices, if combined with other factors, could have a material adverse effect on our results of operations and cash available for distribution. Additionally, cheaper conventional fuel sources or competing renewable resources could also have a negative impact on the power prices we are able to negotiate upon the expiration of our current power sale agreements or upon entering into a power sale agreement for a subsequently acquired power project. As a result, the price of our electricity or RECs subject to the open market could be materially and adversely affected, which could, in turn, have a material adverse effect on our results of operations and cash available for distribution. Accordingly, in such event, our future growth prospects could be adversely affected if we remain solely focused on renewable energy projects and are unable to transition to conventional power projects such as gas-fired power projects.

Operational problems and natural events may cause our electricity generation to fall below our expectations.

Our electricity generation levels depend upon our ability to maintain the working order of our wind turbines and balance of the plant. A natural disaster, severe weather, accident, failure of major equipment, shortage of or inability to acquire critical replacement or spare parts, failure in the operation of any future transmission facilities that we may acquire, including the failure of interconnection to available electricity transmission or distribution networks, could damage or require us to shut down our turbines or related equipment and facilities, impeding our ability to maintain and operate our facilities and decreasing electricity generation levels and our revenues. For example, our Ocotillo and Santa Isabel (Siemens) and Gulf Wind (MHI) projects had experienced certain blade failures in 2013 and 2014. We believe the Siemens blade failures have been fully addressed through the completion of an agreed inspection and repair program. With respect to MHI, we worked with MHI to complete a root cause analysis, testing of the blades at the Gulf Wind facility, and development of a protocol for determining whether a blade might pose a threat to long-term reliable operation. While we reached in November 2015 a long term arrangement with MHI to address potential deficiencies and, if applicable, mitigation for lost revenue resulting from blade downtime at the facility, no assurances can be given that potential deficiencies will not in fact continue to occur and result in blade failures, or that any such effects will not have a material adverse effect on our business, financial condition and results of operation.

In addition, replacement and spare parts for wind turbines and key pieces of electrical equipment may be difficult or costly to acquire or may be unavailable. Sources for some significant spare parts and other equipment are often located outside of the jurisdictions in which our power projects operate. Additionally, our operating projects generally do not hold spare substation main transformers. These transformers are designed specifically for each wind power project, and order lead times can be lengthy. If one of our projects had to replace any of its substation main transformers, it would be unable to sell all of its power until a replacement is installed. To the extent we experience a prolonged interruption at one of our operating projects due to natural events or operational problems and such events are not fully covered by insurance, our electricity generation levels and revenues could materially decrease, which could have a material adverse effect on our business, financial condition and results of operation.

In addition, climate change may have the long-term effect of changing wind patterns at our projects. Changing wind patterns could cause changes in expected electricity generation. These events could also degrade equipment or components and the interconnection and transmission facilities’ lives or maintenance costs. Even though our projects typically enter into warranty agreements with the turbine manufacturer for two- to ten-year terms, such agreements are typically subject to an aggregate maximum cap and there can be no assurance that the supplier will be able to fulfill its contractual obligations.

We have a limited operating history and our growth may make it difficult for us to manage our project expansion efficiently.

We have a relatively new portfolio of assets, including several projects that have only recently commenced commercial operations. Stockholders should consider our prospects in light of the risks and uncertainties growing companies encounter in rapidly evolving industries such as ours. Also, our anticipated near-term growth could make it difficult for us to manage our project expansion efficiently due to an inability to employ a sufficient number of skilled personnel or otherwise to effectively manage our capital expenditures and control our costs, including the requisite general and administrative costs necessary to achieve our anticipated growth. These challenges could adversely affect our ability to manage our current or future operating projects in an efficient manner and complete construction of our construction projects in a timely manner, either of which could have a material adverse effect on our business, financial condition and results of operation.

Our operations are subject to numerous environmental, health and safety laws and regulations.

Our projects are subject to numerous environmental, health and safety laws and regulations in each of the jurisdictions in which our projects operate or will operate. These laws and regulations require our projects to obtain and maintain permits and approvals, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the siting, construction, operation and decommissioning of power projects. For example, to obtain permits some projects are, in certain cases, required to undertake programs to protect and maintain local endangered or threatened species. If such programs are not successful, our projects could be subject to increased levels of mitigation, penalties or revocation of our permits. Violations of environmental and other laws, regulations and permit requirements, including certain violations of laws protecting wetlands, migratory birds, bald and golden eagles and threatened or endangered species, may also result in criminal sanctions or injunctions. In addition, if our projects do not comply with applicable laws, regulations or permit requirements, or if there are endangered or threatened species fatalities at our projects, we may be required to pay penalties or fines or curtail or cease operations of the affected projects. For example, in connection with a permit we obtained at our Spring Valley wind facility, we had to adopt a mitigation plan with respect to injuries and fatalities to golden eagles, and were required to establish a process in the event of incidents, including reporting to the U.S. Fish and Wildlife Service. We have followed such required processes in connection with three golden eagle incidents since January 1, 2013, and, in addition, we have filed an application for an eagle take permit which is under consideration by the U.S. Fish and Wildlife Service. While we have recently entered into an agreement with U.S. Fish and Wildlife to fund additional research into mitigation measures and incurred nominal fines with respect to the prior eagle incidents, no assurances can be given that we will not be required to implement further increased levels of mitigation, or face additional penalties,

fines, or other measures as a result of golden eagle incidents at our Spring Valley facility or any of our other wind facilities. In addition, no assurances can be given that our eagle take permit will be approved.
No assurances can be given that our application for an eagle take permit will be approved, or that we will not be required to implement increased levels of mitigation, or face penalties, fines, or other measures as a result of prior or future golden eagle incidents at our Spring Valley facility or any of our other wind facilities.
Certain environmental laws impose liability on current and previous owners and operators of real property for the cost of removal or remediation of hazardous substances, even if the owner or operator did not know of, or was not responsible for, the release of such hazardous substances. In addition to actions brought by governmental agencies, private plaintiffs may also bring claims arising from the presence of hazardous substances on a property or exposure to such substances. Our projects' liabilities at properties we own or operate arising from past releases of, or exposure to, hazardous substances could have a material adverse effect on our business, financial condition and results of operations.
Environmental, health and safety laws, regulations and permit requirements may change and become more stringent. Any such changes could require our projects to incur additional material costs or cause our projects to suffer adverse consequences. For example, the Ministry of Environment in Ontario has established regulatory requirements governing noise restrictions for wind farms which are an integral part of the permitting framework for our projects in that jurisdiction. In the event of changes in either the regulatory requirements or permitting framework, there is risk that our projects that were designed for compliance within the existing framework and requirements for noise could still be evaluated by regulators as noncompliant. These risks are enhanced because testing for compliance with noise requirements is technically complex, carries some degree of uncertainty, and does not have significant precedent in that market. In the event of a determination of noncompliance, there is risk that the necessary mitigation, which would likely need to occur during periods of higher wind speeds, could require curtailment of energy production at the facility, with a resulting reduction in revenues.
Our projects' costs of complying with current and future environmental, health and safety laws, regulations and permit requirements (including any change in noise regulations), and any liabilities, fines or other sanctions resulting from violations of them, could have a material adverse effect on our business, financial condition and results of operations.
We may be unable to complete any future construction projects on time, and our construction costs could increase to levels that make a project too expensive to complete or make the return on our investment in that project less than expected.
While we currently do not have projects in construction, there may be delays or unexpected developments in completing any future construction projects, which could cause the construction costs of these projects to exceed our expectations. Our construction projects are typically constructed under fixed-price and fixed-schedule contracts with construction and equipment suppliers. However, these contracts typically provide for limitations on the liability of these contractors to pay us liquidated damages for cost overruns and construction delays. We may suffer significant construction delays or construction cost increases as a result of underperformance of these contractors and equipment suppliers, as well as other suppliers, to our projects. No assurances can be given that disputes with our project construction providers will not arise in the future, and if they do, we can reach a settlement, such settlement amount would be covered by the remaining budgeted project contingencies or otherwise be favorable, arbitration or legal action would not be commenced, or we would not have to bear increased costs associated with any such disputes which could make the return on our investment in the project less than expected.
Additionally, various other factors could contribute to construction-cost overruns and construction delays, including:

- inclement weather conditions;
- failure to receive turbines or other critical components and equipment necessary to maintain the operating capacity of our projects, in a timely manner or at all;
- failure to complete interconnection to transmission networks, which relies on several third parties, including interconnection facilities provided by local utilities;
- failure to maintain all necessary rights to land access and use;
- failure to receive quality and timely performance of third-party services;

- failure to maintain environmental and other permits or approvals;
- failure to meet domestic content requirements;

- appeals of environmental and other permits or approvals that we hold;
- lawful or unlawful protests by or work stoppages resulting from local community objections to a project;
- shortage of skilled labor on the part of our contractors;
- adverse environmental and geological conditions; and
- force majeure or other events out of our control.

Any of these factors could give rise to construction delays and construction costs in excess of our expectations. These circumstances could prevent our construction projects from commencing operations or from meeting our original expectations about how much electricity they will generate or the returns they will achieve. In addition, substantial delays could cause defaults under our financing agreements or under PPAs that require completion of project construction by a certain date at specified performance levels or could result in the loss or reduction of expected tax benefits. Our inability to transition our construction projects into financially successful operating projects would have a material adverse effect on our business, financial condition and results of operations and our ability to pay dividends.

Our projects rely on interconnections to transmission lines and other transmission facilities that are owned and operated by third parties. Our projects are exposed to interconnection and transmission facility development and curtailment risks, which may delay the completion of any construction projects or reduce the return to us on those investments.

Our projects depend upon interconnection to electric transmission lines owned and operated by regulated utilities to deliver the electricity we generate. A failure or delay in the operation or development of these interconnection or transmission facilities could result in our losing revenues because such a failure or delay could limit the amount of power our operating projects deliver or delay the completion of any construction projects. In addition, in those countries in which we have operating projects, certain of our operating projects' generation of electricity may be curtailed without compensation due to transmission limitations or limitations on the electricity grid's ability to accommodate intermittent electricity generating sources, reducing our revenues and impairing our ability to capitalize fully on a particular project's potential. Such a failure or curtailment at levels above our expectations could have a material adverse effect on our business, financial condition and results of operations.

In the future we may acquire projects with their own generator leads to available electricity transmission or distribution networks. In some cases, these facilities may cover significant distances. A failure in our operation of these facilities that causes the facilities to be temporarily out of service, or subject to reduced service, could result in lost revenues because it could limit the amount of electricity our operating projects are able to deliver. In addition, in many of the markets in which we operate or are looking to expand, should there be any excess capacity available in those generator lead facilities, and should a third party request access to such capacity, the relevant regulatory authority in such jurisdiction, such as FERC in the United States, or other authorities might, require our projects to provide service over such facilities for that excess capacity to the requesting third party at regulated rates. Should this occur in markets with such regulations, the projects could be subject to additional regulatory risks and costly compliance burdens associated with being considered the owner and operator of a transmission facility.

The loss of one or more of our executive officers or key employees may adversely affect our ability to effectively manage our operating projects and complete any construction projects on schedule.

We depend on our experienced management team and the loss of one or more key executives could have a negative impact on our business. We also depend on our ability to retain and motivate key employees and attract qualified new employees. Because the wind power industry is relatively new, there is a scarcity of experienced employees in the wind power industry. We may not be able to replace departing members of our management team or key employees. Integrating new executives into our management team and training new employees with no prior experience in the power industry could prove disruptive to our projects, require a disproportionate amount of resources and management attention and ultimately prove unsuccessful. An inability to attract and retain sufficient technical and managerial personnel could limit our ability to effectively manage our operating projects and complete any construction projects on schedule and within budget, which could have a material adverse effect on our business, financial condition and results of operations.

The employee transfer may adversely affect our costs.

In July 2015, we amended the agreement relating to the employee transfer event to provide that the employee transfer event is no longer conditioned upon our achievement of $2.5 billion in market capitalization. Instead, we have the option, exercisable at any time until January 1, 2017 to require the employee transfer event to occur. Following the occurrence of the employee transfer event, we will be faced with increased costs associated with employing a larger number of employees. If Pattern Development reduces the scope of its development activities and is therefore not paying us for the services of the transferred employees pursuant to the terms of the Management Services Agreement and our development activities remain insignificant, we may not immediately require the services of all such employees. Such events could have a material adverse effect on our business, financial condition and results of operation.

Our use and enjoyment of real property rights for our projects may be adversely affected by the rights of lienholders and leaseholders that are superior to those of the grantors of those real property rights to our projects.

Our projects generally are, and any of our future projects are likely to be, located on land occupied pursuant to long-term easements, leases and rights-of-way. The ownership interests in the land subject to these easements, leases and rights-of-way may be subject to mortgages securing loans or other liens (such as tax liens) and other easement, lease rights and rights-of-way of third parties (such as leases of oil or mineral rights) that were created prior to our projects' easements, leases and rights-of-way. As a result, certain of our projects' rights under these easements, leases or rights-of-way may be subject, and subordinate, to the rights of those third parties. We perform title searches, obtain title insurance and enter into non-disturbance agreements to protect ourselves against these risks. Such efforts may, however, be inadequate to protect our operating projects against all risk of loss of our rights to use the land on which our projects are located, which could have a material adverse effect on our business, financial condition and results of operations. In addition, certain lands, such as lands under the jurisdiction of the U.S. Department of Interior's Bureau of Land Management, or the "Bureau of Land Management," are subject to contractual rights that permit the Bureau of Land Management to adjust rent due on properties and other obligations, such as the amount of required reclamation security, to market terms. Any such loss or curtailment of our rights to use the land on which our projects are located, any increase in rent due, or any increase in other obligations with respect to such lands could have a material adverse effect on our business, financial condition and results of operations.

Our operating projects are, and other future projects may be, subject to various governmental regulations, approvals, and compliance requirements that regulate the sale of electricity, which could have a material adverse effect on our business, financial condition and results of operations.

Our current projects in operation in the United States are operating as "Exempt Wholesale Generators," or "EWGs," as defined under the Public Utility Holding Company Act of 2005, as amended, or "PUHCA," and therefore are exempt from certain regulation under PUHCA. Other than Gulf Wind, Panhandle 1, Panhandle 2, and Logan's Gap, our operating projects in the United States are, however, public utilities under the Federal Power Act subject to rate regulation by FERC. Our future projects in the United States will also likely be subject to such rate regulation once they are placed into service. Our projects in the United States that are subject to FERC rate regulation are required to obtain acceptance of their rate schedules for wholesale sales of energy (i.e., not retail sales to consumers), capacity and ancillary services, including their ability to charge "market-based rates." FERC may revoke or revise an entity's authorization to make wholesale sales at market-based rates if FERC subsequently determines that such entity and its affiliates can exercise horizontal or vertical market power, create barriers to entry or engage in abusive affiliate transactions or market manipulation. In addition, public utilities in the United States are subject to FERC reporting requirements that impose administrative burdens and that, if violated, can expose the company to criminal and civil penalties or other risks.

Most of our North American projects are located in regions in which the wholesale electric markets are administered by ISOs and Regional Transmission Organizations, or "RTOs." Several of our current operating projects are subject to the California ISO, or "CAISO," which is the ISO that prescribes rules for the terms of participation in the California energy market; ERCOT, which is the ISO that prescribes the rules for and terms of participation in the Texas energy market; and the Independent Electricity System Operator, or "IESO," which is the ISO that administers the wholesale electricity market in Ontario. The Southwest Power Pool is the RTO and regional market administrator for our Post Rock project. Lost Creek is in the Associated Electric Cooperative, Inc. a subregion of the SERC Reliability Corporation. Many of these entities can impose rules, restrictions and terms of service that are quasi-regulatory in nature and can have a material adverse impact on our business. For example, ISOs and RTOs have developed bid-based locational pricing rules for the energy markets that they administer. In addition, most ISOs and RTOs have also developed bidding, scheduling and market behavior rules, both to curb the potential exercise of market power by electricity generating companies and to ensure certain market functions and system reliability. These actions could materially adversely affect our ability to sell, and the price we receive for, our energy, capacity and ancillary services. All of our current operating projects located in North America are also subject to the reliability standards of the North American Electric Reliability Corporation, or "NERC." If we fail to comply with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. Although our U.S. projects are not subject to state utility regulation because our projects sell power exclusively on a wholesale basis, we are subject to certain state regulations that may affect the sale of electricity from our projects, the operations of our projects, as well as the potential for state electricity taxes. All of our current operating projects in Canada are subject to exclusive provincial regulatory authority with respect to the generation and production of electricity, which varies across provincial jurisdictions. Changes in regulatory treatment at the state and provincial level are difficult to predict and could have a significant impact on our ability to operate and on our financial condition and results of operations.

Our industry could be subject to increased regulatory oversight.

Our industry could be subject to increased regulatory oversight. Changing regulatory policies and other actions by governments and third parties with respect to curtailment of electricity generation, electricity grid management restrictions, interconnection rules and transmission may all have the effect of limiting the revenues from, and increasing the operating costs of, our projects which could have a material adverse effect on our business, financial condition and results of operations.

Due to regulatory restructuring initiatives at the federal, provincial and state levels, the electricity industry has undergone changes over the past several years. Future government initiatives will further change the electricity industry. Some of these initiatives may delay or reverse the movement towards competitive markets. We cannot predict the future design of wholesale power markets or the ultimate effect that on-going regulatory changes will have on our business, financial condition and results of operations.

Our projects are not able to insure against all potential risks and may become subject to higher insurance premiums.

Our projects are exposed to the risks inherent in the construction and operation of wind power projects, such as breakdowns, manufacturing defects, natural disasters, terrorist attacks and sabotage. We are also exposed to environmental risks. We have insurance policies covering certain risks associated with our business. Our insurance policies do not, however, cover losses as a result of certain force majeure events or terrorism. In addition, our insurance policies for our projects may cover losses as a result of certain types of natural disasters or sabotage, among other things, but such coverage is not always available in the insurance market on commercially reasonable terms and is often capped at predetermined limits that may not be adequate. In addition, our insurance policies are subject to annual review by our insurers and may not be renewed on similar or favorable terms or at all. A serious uninsured loss or a loss significantly exceeding the limits of our insurance policies could have a material adverse effect on our business, financial condition and results of operations.

Currency exchange rate fluctuations may have an impact on our financial results and condition.

We have exposures to currency exchange rate fluctuations, primarily the Canadian dollar, related to buying, selling and financing our business in currencies other than the local currencies of the countries in which we operate. A portion of our revenue for the years ended December 31, 2015, 2014 and 2013 was denominated in currencies other than the U.S. dollar, and we expect net revenue from non-U.S. dollar markets to continue to represent a portion of our net revenue. We manage our currency exposure through a variety of methods, including efforts to match our asset and liabilities in the same currencies, mainly by raising local currency debt. In addition, we have implemented a currency hedging program to manage short and medium term fluctuations in our dividends from our wind facilities located outside the United States. However, any measures that we have implemented or may implement in the future to reduce the effect of currency exchange rate fluctuations and other risks of our global operations may not be effective or may be expensive. We cannot provide assurance that currency exchange rate fluctuations will not otherwise have a material adverse effect on our financial condition or results of operations or cause significant fluctuations in quarterly and annual results of operations.

Foreign currency translation risk arises upon the translation of statement of financial position and income statement items of our foreign subsidiaries whose functional currency is a currency other than the U.S. dollar into U.S. dollars for purposes of preparing the consolidated financial statements included elsewhere in this Form 10-K, which are presented in U.S. dollars. The assets and liabilities of our non-U.S. dollar denominated subsidiaries are translated at the closing rate at the date of reporting and income statement items are translated at the average rate for the period. All resulting exchange differences are recognized in a separate component of equity, “Foreign currency translation, net of tax,” and are recorded in “Other comprehensive income (loss), net of tax.” These currency translation differences may have significant negative or positive impacts. Upon the disposal of a non-U.S. dollar denominated subsidiary, the cumulative amount of exchange differences relating to that non-U.S. dollar denominated subsidiary are reclassified from equity to profit or loss. Our foreign currency translation risk mainly relates to our operations in Canada.

In addition, foreign currency transaction risk arises when we or our subsidiaries enter into transactions where the settlement occurs in a currency other than the functional currency of us or our subsidiary. Exchange differences (gains and losses) arising on the settlement of monetary items or on translation of monetary items at rates different from those at which they were translated on initial recognition during the period or in previous financial statements are recognized in profit or loss in the period in which they arise. In order to reduce significant foreign currency transaction risk from our operating activities, we may use forward exchange contracts to hedge forecasted cash inflows and outflows. Furthermore, most non-U.S. dollar denominated debts are held by non-U.S. dollar denominated subsidiaries in the same functional currency of those subsidiary operations.

Our cross-border operations require us to comply with anti-corruption laws and regulations of the U.S. government and various non-U.S. jurisdictions.

Doing business in multiple countries requires us and our subsidiaries to comply with the laws and regulations of the U.S. government and various non-U.S. jurisdictions. Our failure to comply with these rules and regulations may expose us to liabilities. These laws and regulations may apply to our companies, individual directors, officers, employees and agents and may restrict our operations, trade practices, investment decisions and partnering activities. In particular, our non-U.S. operations are subject to U.S. and foreign anti-corruption laws and regulations, such as the Foreign Corrupt Practices Act of 1977, or the "FCPA." The FCPA prohibits U.S. companies and their officers, directors, employees and agents acting on their behalf from corruptly offering, promising, authorizing or providing anything of value to foreign officials for the purposes of influencing official decisions or obtaining or retaining business or otherwise obtaining favorable treatment. The FCPA also requires companies to make and keep books, records and accounts that accurately and fairly reflect transactions and dispositions of assets and to maintain a system of adequate internal accounting controls. As part of our business, we deal with state-owned business enterprises, the employees and representatives of which may be considered foreign officials for purposes of the FCPA. As a result, business dealings between our employees or our agents and any such foreign official could expose our company to the risk of violating anti-corruption laws even if such business practices may be customary or are not otherwise prohibited between our company and a private third-party. Violations of these legal requirements are punishable by criminal fines and imprisonment, civil penalties, disgorgement of profits, injunctions, debarment from government contracts as well as other remedial measures. We have established policies and procedures designed to assist us and our personnel in complying with applicable U.S. and non-U.S. laws and regulations; however, we cannot assure stockholders that these policies and procedures will completely eliminate the risk of a violation of these legal requirements, and any such violation (inadvertent or otherwise) could have a material adverse effect on our business, financial condition and results of operations.

We own, and in the future may acquire, certain projects in joint ventures, and our joint venture partners' interests may conflict with our and our stockholders' interests.

We own, and in the future may acquire, certain projects in joint ventures, including South Kent, Grand and K2, in each of which we have a 50%, 45% and 33% interest, respectively, and El Arrayán, in which we have a 70% interest. In the future, we may invest in other projects with a joint venture partner, including certain Pattern Development-owned projects. Joint ventures inherently involve a lesser degree of control over business operations, which could result in an increase in the financial, legal, operational or compliance risks associated with a project, including, but not limited to, variances in accounting and internal control requirements. To the extent we do not have a controlling interest in a project, our joint venture partners could take actions that decrease the value of our investment and lower our overall return. In addition, conflicts of interest may arise in the future between our company and our stockholders, on the one hand, and our joint venture partners, on the other hand, where our joint venture partners' business interests are inconsistent with our and our stockholders' interests. Further, disagreements or disputes between us and our joint venture partners may arise which could result in litigation, increase our expenses and potentially limit the time and effort our officers and directors are able to devote to our business, all of which could have a material adverse effect on our business, financial condition and results of operations.

Security breaches, including cybersecurity breaches, and other disruptions could compromise our business operations and critical and proprietary information and expose us to liability, which could adversely affect our business, financial condition and reputation.

In the ordinary course of our business, we store sensitive data and proprietary information regarding our business, employees, shareholders, offtakers, service providers, business partners and other individuals in our data center and on our network. Additionally, we use and are dependent upon information technology systems that utilize sophisticated operational systems and network infrastructure to run our wind farms. Through our 24/7 operations control center, we can, among other things, monitor and control each wind turbine, monitor regional and local climate, track real time market prices and, for some of our projects, monitor certain environmental activities. The secure maintenance of information and information technology systems is critical to our operations. Despite security measures we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to attacks by hackers or terrorists as a result of the rise in the sophistication and volume of cyberattacks. Also, our information and information technology systems may be breached due to viruses, human error, malfeasance or other malfunctions and disruptions. Any such attack or breach could: (i) compromise our turbines and wind farms thereby adversely affecting generation and transmission to the grid; (ii) adversely affect our operations; (iii) corrupt data; or (iv) result in unauthorized access to the information stored on our networks, including, company proprietary information and employee data causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such attack, breach, access, disclosure or other loss of information could result in lost revenue, the inability to conduct critical business functions, legal claims or proceedings, regulatory penalties, increased regulation, increased protection costs for enhanced cyber security systems or personnel, damage to our reputation and/or the rendering of our disclosure controls and procedures ineffective, all of which could adversely affect our business, financial condition and reputation.

Risks Related to Future Growth and Acquisitions

The growth of our business depends on locating and acquiring interests in additional attractive independent power and transmission projects .

Our business strategy includes acquiring power projects that are either operational, construction-ready, or in limited circumstances, under development. We intend to pursue opportunities to acquire projects from third-party IPPs where we may submit bids from time to time, and from Pattern Development pursuant to our Purchase Rights. In addition, we and the equity owners of Pattern Development have begun discussions regarding a potential investment by us in a portion of the business of Pattern Development. Various factors could affect the availability of attractive projects to grow our business, including:

- competing bids for a project, including a project subject to our Purchase Rights, from other IPPs, including companies that may have substantially greater capital and other resources than we do;
- fewer third-party acquisition opportunities than we expect, which could result from, among other things, available projects having less desirable economic returns or higher risk profiles than we believe suitable for our business plan and investment strategy;
- Pattern Development’s failure to complete the development of (i) the Identified ROFO Projects, which could result from, among other things, permitting challenges, failure to procure the requisite financing, equipment or interconnection, or an inability to satisfy the conditions to effectiveness of project agreements such as PPAs and (ii) any of the other projects in its development pipeline, in a timely manner, or at all, in either case, which could limit our acquisition opportunities under our Purchase Rights;
- our failure to exercise our Purchase Rights or acquire assets from Pattern Development;
- our failure to successfully develop and finance projects, to the extent that we decide to pursue development activities with respect to new power projects;
- local opposition to wind turbine installations is growing in certain markets due to concerns about noise, health and other alleged impacts of wind power projects. In addition, indigenous communities in the United States and Canada, including Native Americans and First Nations, are becoming more involved in the development of wind power projects and have certain treaty rights that can negatively affect the viability of power projects. As a result, for these and other reasons, litigation and challenges to wind power projects has increased; and
- limited access to capital may impair our ability to buy certain projects or buy them at the time we had expected.

Any of these factors could prevent us from executing our growth strategy or otherwise have a material adverse effect on our business, financial condition and results of operations.

Additionally, even if we consummate acquisitions that we believe will be accretive to cash available for distribution per share, those acquisitions may in fact result in a decrease in cash available for distribution per Class A share as a result of incorrect assumptions in our evaluation of such acquisitions, unforeseen consequences or other external events beyond our control. Furthermore, if we consummate any future acquisitions, our capitalization and results of operations may change significantly, and stockholders will not generally have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Capital market conditions can have an effect on both our timing and ability to consummate future acquisitions.

Since we often finance acquisitions of clean energy projects partially or wholly through the issuance of additional Class A shares, we may need to be able to access the capital markets on commercially reasonable terms when acquisition opportunities arise. For example, we utilized in part proceeds from underwritten public offerings of our Class A shares in both July 2015 and February 2015 and a private placement of convertible debt securities in July 2015 for investment in acquisition opportunities and to repay other debt previously incurred to finance acquisition opportunities. Our ability to access the equity capital markets is dependent on, among other factors, the overall state of the capital markets and investor appetite for investment in clean energy projects in general and our Class A shares in particular. Volatility in the market price of our Class A shares may prevent or limit our ability to utilize our equity securities as a source of capital to help fund acquisition opportunities. During 2015, the prices for our Class A shares traded on The NASDAQ Global Select Market ranged from a high of $32.00 to a low of $16.96. On February 24, 2016, the last reported sale price of our Class A shares on such market was $16.40. An inability to obtain equity financing on commercially reasonable terms could significantly limit our timing and ability to consummate future acquisitions, and to effectuate our growth strategy. In addition, the issuance of additional Class A shares in connection with acquisitions, particularly if consummated at depressed price levels, could cause significant shareholder dilution and reduce the cash distribution per share if the acquisitions are not sufficiently accretive.

In the event we determine it is not economical to utilize, or we are unable to utilize our equity securities as a source of capital to fund acquisition opportunities, we may need to consider utilizing other sources of capital, such as cash on hand, borrowings under our existing credit facilities, arranging additional credit facilities, or the issuance of debt securities, none of which may be available or may not be available at attractive terms. Our inability to effectively consummate future acquisitions could have a material adverse effect on our ability to grow our business and make cash distributions to our shareholders.

Acquisition of power projects involves numerous risks.

Our strategy includes acquiring power projects. The acquisition of power projects involves numerous risks, many of which may not be able to be discovered through our due diligence process, including exposure to previously existing liabilities and unanticipated costs associated with the pre-acquisition period; difficulty in integrating the acquired projects into our existing business; and, if the projects are in new markets, the risks of entering markets where we have limited experience. While we will perform our due diligence on prospective acquisitions, we may not be able to discover all potential operational deficiencies in such projects or problematic wind characteristics. A failure to achieve the financial returns we expect when we acquire power projects could have a material adverse effect on our ability to implement our growth strategy and, ultimately, our business, financial condition and results of operations.

Our growth strategy is dependent upon the acquisition of attractive power projects developed by third-parties, including Pattern Development, and an inability of such development companies to obtain the requisite financing to develop and construct projects could have a material adverse effect on our ability to grow our business.

Power project development is a capital intensive, high-risk business that relies heavily on and, therefore, is subject to the availability of debt and equity financing sources to fund projected construction and other projected capital expenditures. As a result, in order to successfully develop a power project, development companies, including Pattern Development, from which we may seek to acquire power projects, must obtain at-risk funds sufficient to complete the development phase of their projects. We, on the other hand, must anticipate obtaining funds from equity or debt financings, including tax equity transactions, or from government grants in order to successfully complete our acquisitions and fund any required construction and other capital costs of the acquired projects. We currently intend to acquire power projects that are at least at the stage of being construction-ready, which is generally the point in time when the project is able to procure construction financing. Any significant disruption in the credit and capital markets, or a significant increase in interest rates, could make it difficult for development companies to successfully develop attractive projects as well as limit a project’s ability to obtain financing to complete any construction of a project we may seek to acquire. If development companies from which we seek to acquire projects are unable to raise funds when needed or if we or they are unable to secure construction financing, the ability to grow our project portfolio may be limited, which could have a material adverse effect on our ability to implement our growth strategy and, ultimately, our business, financial condition and results of operations.

Our ability to grow our cash available for distribution is substantially dependent on our ability to make acquisitions from Pattern Development or third parties on economically favorable terms.

Our goal of growing our cash available for distribution and increasing dividends to our Class A stockholders is substantially dependent on our ability to make and finance acquisitions on terms that result in an increase in cash available for distribution per Class A share. To grow our cash available for distribution per Class A share through acquisitions, we must be able to acquire new generation assets, such as the Identified ROFO Projects, on economically favorable terms. If we are unable to make accretive acquisitions from Pattern Development or third parties because we are unable to identify attractive acquisition opportunities, negotiate acceptable purchase contracts, obtain financing on economically acceptable terms (as a result of the then current market value of our Class A shares or otherwise) or are outbid by competitors, we may not be able to realize our targeted growth in cash available for distribution per Class A share.

The energy industry in the markets in which we operate, as well as the markets we are looking to expand into, benefit from governmental support that is subject to change.

The energy industry in the markets in which we operate and are looking to expand into, including both fossil fuel and renewable energy sources, in general benefits from various forms of governmental support. Renewable energy sources in Canada benefit from federal and provincial incentives, such as RPS programs, accelerated cost recovery deductions, the availability of off-take contracts through RFP and standard offer programs including the Hydro-Quebec call for tenders, the Ontario feed-in tariff and large renewable procurement programs, and other commercially oriented incentives. Renewable energy sources in the United States have benefited from various federal and state governmental incentives, such as PTCs, ITCs, ITC cash grants, loan guarantees, RPS programs and accelerated tax depreciation. PTCs and ITCs for wind energy on the federal level were extended in December 2015. The extension extended the expiration date for tax credits for wind facilities with a five year phase-down for wind projects commencing construction after December 31, 2014. Renewable energy sources in Chile benefit from the Renewable and Non-Conventional Energy Law, which stipulates that by 2025 a portion of the total energy withdrawn from the grid, starting with 5% in 2015 and progressively increasing up to 20% by 2025, shall be produced with renewable and non-conventional technologies. Such obligations translate into “green attributes” which can be freely traded. In 2012, Japan introduced a feed-in-tariff program that offered fixed term, fixed price contracts of up to 20 years to renewable power projects. The Mexican congress has established a mandate that at least 35% of its energy consumption be supplied by clean sources by 2024. While such developments extending various forms of governmental support provide general benefits to the wind power industry in which we operate, to the extent that these governmental incentive programs may be amended or changed in the future, particularly if amendments or changes are unexpected or unfavorable and after we have developed long-term business plans and strategies based upon them, it could adversely affect the price of electricity sold to power purchasers generated by developed or planned wind power projects, decrease demand for wind power, or reduce the number of projects available to us for acquisition, any of which could have a material adverse effect on our ability to implement our growth strategy and, ultimately, our business, financial condition and results of operations. For example, in February 2016, the U.S. Supreme Court issued a stay prohibiting the implementation of the Clean Power Plan, a regulation issued by the U.S. Environmental Protection Agency aimed at reducing use of existing coal-fired electricity generation facilities and increasing renewable generation in order to reduce greenhouse gas emissions, pending a challenge to such regulation before a U.S. Court of Appeals.

Wind power procurement in Canada is a provincial matter, with relatively irregular, infrequent and competitive procurement windows.

Each province in Canada has its own regulatory framework and renewable energy policy, with few material federal policies to drive the growth of renewable energy. Renewable energy developers must anticipate the future policy direction in each of the provinces, and secure viable projects before they can bid to procure a PPA through highly competitive PPA auctions. Most markets are relatively small. Energy policy in our key market of Ontario is subject to a political process, including with respect to its FIT program, and renewable energy procurement may change dramatically as a result of changes in the provincial government or political climate.

We face competition primarily from other renewable energy IPPs and, in particular, other wind power companies.

We believe our primary competitors are infrastructure funds and some wind power companies or IPPs focused on renewable energy generation. We compete with these companies to acquire well-developed projects with projected stable cash flows that can be built in a cost-effective manner. We also compete with other wind power developers and operators for the limited pool of personnel with requisite industry knowledge and experience. Furthermore, in recent years, there have been times of increased demand for wind turbines and their related components, causing turbine suppliers to have difficulty meeting the demand. If these conditions return in the future, turbine and other component manufacturers may give priority to other market participants, including our competitors, who may have resources greater than ours.

We compete with other renewable energy companies (and power companies in general) for the lowest cost financing, which provides the highest returns for our projects. Once we have acquired a construction project and put it into operation, we may compete on price if we sell electricity into power markets at wholesale market prices. Depending on the regulatory framework and market dynamics of a region, we may also compete with other wind power companies and other renewable energy generators, when our projects bid on or negotiate for long-term power sale agreements or sell electricity or RECs into the spot-market. Our ability to compete on price with other wind power companies and other renewable energy IPPs may be negatively impacted if the regulatory framework of a region favors other sources of renewable energy over wind power.

We have no control over where our competitors may erect wind power projects. Our competitors may erect wind power projects adjacent to our wind projects that may cause upwind array losses to occur at our wind projects.

Upwind array losses reflect the diminished wind resource available at a project resulting from interference with available wind caused by adjacent wind turbines. An adjacent wind power project that causes upwind array losses could have a material adverse effect on our revenues and results of operations.

Any change in power consumption levels could have a material adverse effect on our business, financial condition and results of operations.

The amount of wind power consumed by the electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations and the price and availability of fuels such as nuclear, coal, natural gas and oil as well as other sources of renewable energy. A decline in prices for these fuels could cause demand for wind power to decrease and adversely affect the demand for renewable energy. For example, low natural gas prices have led, in some instances, to increased natural gas consumption by electricity-generating utilities in lieu of other power sources. To the extent renewable energy and wind power, in particular, becomes less cost-competitive on an overall basis as a result of a lack of governmental incentives, cheaper alternatives or otherwise, demand for wind power and other forms of renewable energy could decrease. Slow growth in overall demand for electricity or a long-term reduction in the demand for renewable energy could have a material adverse effect on our plan to grow our business and could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Some states and provinces with RPS programs have met, or will in the near future, meet such targets through projects under contract, which could cause demand for new wind power and other power capacity to decrease.

Some states and provinces with RPS targets have met, or in the near future will meet, their targets through the recent increase in renewable energy development activity. For example, the Canadian province of Ontario has a renewable energy target of 10.7 GW, excluding hydroelectric sources. Presently, the province anticipates meeting its target by 2018. California, which has one of the most aggressive RPS in the United States, is poised to meet its current target of 25% renewable energy generation by 2016 and had the potential to meet a prior goal of 33% renewable power generation by 2020 with already-proposed new renewable power projects, although such target had recently been increased to 50%. As a result of achieving targets, and if such U.S. states and Canadian provinces with targets do not increase targets in the future, like California has done, demand for additional wind power generating capacity could decrease. In addition, to the extent other states and provinces do not become market leaders in their stead or increase their RPS targets, demand for power from wind power and other renewable energy projects could decrease in the future, which could have a material adverse effect on our business, financial condition and results of operations. For example, Ohio in 2014 became the only state to freeze its RPS, effectively stopping the state’s mandates for renewable energy and efficiency until 2017. While in 2017 the standards in Ohio are expected pick up where they left off prior to the freeze, a committee is reviewing changes to the RPS which has created an atmosphere of uncertainty for renewable energy investment in the state.

New projects being developed that we may acquire may need governmental approvals and permits, including environmental approvals and permits, for construction and operation. Any failure to obtain necessary permits could adversely affect the amount of our growth.

The design, construction and operation of wind power projects are highly regulated, require various governmental approvals and permits, including environmental approvals and permits, and may be subject to the imposition of related conditions that vary by jurisdiction. In some cases, these approvals and permits require periodic renewal and a subsequently issued permit may not be consistent with the permit initially issued. In other cases, these permits may require compliance with terns that can change over time. We cannot predict whether all permits required for a given project will be granted or whether the conditions associated with the permits, as such conditions may change over time, will be achievable. The denial or loss of a permit essential to a project, or the imposition of impractical conditions upon renewal or over time, could impair our ability to construct and operate a project. In addition, we cannot predict whether the permits will attract significant opposition or whether the permitting process will be lengthened due to complexities, legal claims or appeals. Delay in the review and permitting process for a project can impair or delay our ability to construct or acquire a project or increase the cost such that the project is no longer attractive to us.

In developing certain of our projects Pattern Development experienced delays in obtaining non-appealable permits and we may experience delays in the future. For example, when we acquired our Ocotillo project, it was then the subject of four active lawsuits brought by a variety of project opponents, all of which have challenged the prior issuance of Ocotillo’s primary environmental analysis and right-of-way entitlement. We had commenced commercial operations at the Ocotillo project in anticipation of securing favorable rulings on these lawsuits. See Item 3 “Legal Proceedings.” In Ontario, anti-wind advocacy groups opposed the environmental permit granted to our South Kent and Grand projects. The permits were appealed before the Environmental Review Tribunal, which later dismissed the appeals. We are subject to the risk of being unable to complete our projects if any of the key permits are revoked. If this were to occur at any future project, we would likely lose a significant portion of our investment in the project and

could incur a loss as a result, which would have a material adverse effect on our business, financial condition and results of operations.
If we are unable to make an offer, or make an attractive offer, in the event Pattern Development delivered notice that it is seeking a purchaser for the Armow wind facility, or any other project on the identified ROFO list, we may be unable to acquire such project from Pattern Development pursuant to our Project Purchase Right.
While the 180 MW Armow wind facility, an identified ROFO project, reached commercial operations in December 2015, Pattern Development has not yet delivered notice that it is seeking a purchaser for such project under our Project Purchase Right. In addition, the 42 MW Futtsu Solar facility in Japan, which is an identified ROFO project, has become operational. Although Pattern Development may choose to seek a purchaser of a project at a time of its choosing whether earlier in the project's development stage

or later at a time, we have generally anticipated that Pattern Development seeks a purchaser of its development projects upon construction-readiness following commencement of its construction. We do not control Pattern Development, and Pattern Development may deem it necessary or desirable to deliver such notice to us that is seeking a purchaser for its projects at any time for its own capital, liquidity, shareholder, or other requirements. While it is uncertain if or when Pattern Development may deliver a notice that it is seeking a purchaser for the Armow facility under our Project Purchase Right, in the event Pattern Development delivered such a notice, or notice for another project on the identified ROFO list, for which we are unable to, or do not, deliver a written first rights project offer or make an attractive offer to purchase its entire interest in such project, Pattern Development may reject our first rights project offer. Pattern Development may then be able to sell the project to a third party (including a competitor), provided it is at a price not less than 105% of our first rights project offer and other terms not materially less favorable. If this occurred, we would not acquire such project from Pattern Development. An inability to acquire the Armow facility, or any other project on the identified ROFO list, under our Project Purchase Right could materially adversely affect our ability to implement our growth strategy.

In spite of our Pattern Development Purchase Rights, it is possible that Pattern Development itself might be sold to third parties. In addition, both our Purchase Rights and our Pattern Development Purchase Rights may expire, and the Non-Competition Agreement with Pattern Development might terminate.

To the extent we do not exercise our Pattern Development Purchase Rights (or upon their expiration), Pattern Development itself or substantially all of its assets may be sold to third parties, including our competitors. Even if we are interested in exercising the Pattern Development Purchase Rights, Pattern Development may offer at an inopportune time for us, or we may not be able to reach an agreement on pricing or other terms. If we are unable to reach an agreement with Pattern Development or its equity owners or if we decline to make an offer, Pattern Development or its equity owners may seek alternative buyers, which could have a material adverse effect on our ability to implement our growth strategy and, ultimately, our business, financial condition and results of operations.

Additionally, our Project Purchase Right and our Pattern Development Purchase Rights terminate upon the fifth anniversary of the completion of our initial public offering, or October 2, 2018, but are subject to automatic five-year renewals unless either party dissents at the time of renewal. In addition, our Project Purchase Right and our Pattern Development Purchase Rights terminate upon the third occasion on which we decline to exercise our Project Purchase Right with respect to an operational or construction-ready project and following which Pattern Development has sold the project to an unrelated third party. Following termination of our Project Purchase Right and our Pattern Development Purchase Rights, Pattern Development will be under no obligation to offer any of its projects to us, which could have a material adverse effect on our ability to implement our growth strategy and ultimately on our business, financial condition and results of operations.

Once our Purchase Rights terminate, the Non-Competition Agreement with Pattern Development will also terminate, and at such time, Pattern Development will no longer be restricted from competing with us for acquisitions.

The loss of one or more of our Pattern Development’s executive officers or key employees may adversely affect our ability to implement our growth strategy.

In addition to relying on our management team for managing our projects, our growth strategy relies on our and Pattern Development’s executive officers and key employees for their strategic guidance and expertise in the selection of projects that we may acquire in the future. Because the wind power industry is relatively new, there is a scarcity of experienced executives and employees in the wind power industry. As a result, if one or more of our or Pattern Development’s executive officers or key employees leaves or retires, and neither we nor Patten Development are able to find a suitable replacement, our ability to implement our growth strategy may be diminished, which could have a material adverse effect on our business, financial condition and results of operations.

While we currently own only wind power projects, in the future, we may decide to expand our acquisition strategy to include other types of power projects or transmission projects. Any future acquisition of non-wind power projects or transmission projects may present unforeseen challenges and result in a competitive disadvantage relative to our more-established competitors.

In the future, we may expand our acquisition strategy to include other types of power projects or transmission projects. In September 2014, we announced the addition of our first solar project, Conejo Solar, a 104 MW photovoltaic solar power project being constructed in Chile, to our list of Identified ROFO Projects. In June 2015, additional solar projects were added to our list of Identified ROFO Projects which are in Japan, including the 42 MW Futtsu Solar and 14 MW Kanagi Solar projects. There can be no assurance that we will be able to identify other attractive non-wind or transmission acquisition opportunities or acquire such projects at a price and on terms that are attractive or that, once acquired, such projects will operate profitably. Additionally, these acquisitions could expose us to increased operating costs, unforeseen liabilities or risks, and regulatory and environmental concerns associated with entering new sectors of the power industry, including requiring a disproportionate amount of our management's attention and resources, which could have an adverse impact on our business as well as place us at a competitive disadvantage relative to more established non-wind energy market participants. A failure to successfully integrate such acquisitions into our existing project portfolio as a result of unforeseen operational difficulties or otherwise, could have a material adverse effect on our business, financial condition and results of operations.

We are subject to risks associated with litigation or administrative proceedings that could materially impact our operations, including proceedings in the future related to power projects we subsequently acquire.

We are subject to risks and costs, including potential negative publicity, associated with lawsuits, in particular, with respect to environmental claims and lawsuits or claims contesting the construction or operation of our projects. See Item 3 "Legal Proceedings." The result of and costs associated with defending any such lawsuit, regardless of the merits and eventual outcome, may be material and could have a material adverse effect on our operations. In the future, we may be involved in legal proceedings, disputes, administrative proceedings, claims and other litigation that arise in the ordinary course of business related to a power project that we subsequently acquire. For example, individuals and interest groups may sue to challenge the issuance of a permit for a power project or seek to enjoin construction or operation of a power project. We may also become subject to claims from individuals who live in the proximity of our power projects based on alleged negative health effects related to acoustics caused by wind turbines. In addition, we have been and may subsequently become subject to legal proceedings or claims contesting the construction or operation of our power projects. Any such legal proceedings or disputes could delay our ability to complete construction of a power project in a timely manner, or at all, or materially increase the costs associated with commencing or continuing commercial operations at a power project. Settlement of claims and unfavorable outcomes or developments relating to these proceedings or disputes, such as judgments for monetary damages, injunctions or denial or revocation of permits, could have a material adverse effect on our ability to implement our growth strategy and, ultimately, our business, financial condition and results of operations.

Risks Related to Our Financial Activities

Our substantial amount of indebtedness may adversely affect our ability to operate our business and impair our ability to pay dividends.

Our consolidated indebtedness, including the revolving credit facility and issuance in July 2015 of convertible notes, as of December 31, 2015 is approximately $1.77 billion, or approximately 50% of our total capitalization of $3.55 billion at such date. Despite our current consolidated debt levels, we or our subsidiaries may still incur substantially more debt or take other actions which would intensify the risks discussed below.

Approximately $208.1 million of our consolidated indebtedness as of December 31, 2015 represents project-level debt that matures prior to 2021. We do not have available cash or short-term liquid investments sufficient to repay all of this medium-term indebtedness and we have not obtained commitments for refinancing this debt. Therefore, we may not be able to extend the maturity of this indebtedness or to otherwise successfully refinance current maturities if the project finance markets deteriorate substantially or we choose not to raise corporate-level debt in place of project-level debt. Refinancing such indebtedness may force us to accept then-prevailing market terms that are less favorable than the existing indebtedness. If, for any reason, we are unable to refinance the existing indebtedness, those projects may be in default of their existing obligations, which may result in a foreclosure on the project collateral and loss of the project. Any such events could have a material adverse effect on our business, financial condition and results of operations.

Our substantial indebtedness could have important consequences, including, for example:

- failure to comply with the covenants in the agreements governing these obligations could result in an event of default under those agreements, which could be difficult to cure, or result in our bankruptcy;
- our debt service obligations require us to dedicate a substantial portion of our cash flow to pay principal and interest on our debt, thereby reducing the funds available to us for purposes such as capital;
- in the event a project is unable to meet its debt service obligations through its own project cash flows, excess cash flow from other projects may be required to help service such obligations, thereby reducing funds available to pay dividends;
- our limited financial flexibility could reduce our ability to plan for and react to unexpected opportunities; and
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our substantial debt service obligations make us vulnerable to adverse changes in general economic, credit and capital markets, industry and competitive conditions and adverse changes in government regulation and place us at a disadvantage compared with competitors with less debt.

Any of these consequences could have a material adverse effect on our business, financial condition and results of operations. If we do not comply with our obligations under our debt instruments, we may be required to refinance all or part of our existing debt, borrow additional amounts or sell securities, which we may not be able to do on favorable terms or at all. In addition, increases in interest rates and changes in debt covenants may reduce the amounts that we can borrow, reduce our cash flows and increase the equity investment we may be required to make to complete any construction of our projects. These increases could cause some of our projects to become economically unattractive. If we are unable to raise additional capital or generate sufficient operating cash flow to repay our indebtedness, we could be in default under our lending agreements and could be required to delay construction of our wind power projects, reduce overhead costs, reduce the scope of our projects or abandon or sell some or all of our projects, all of which could have a material adverse effect on our business, financial condition and results of operations.

We may not have the ability to raise the funds necessary to settle conversions of the notes we issued in July 2015 in cash, repay such notes at maturity or repurchase such notes upon a fundamental change, and our debt agreements may limit our ability to pay cash upon conversion or repurchase of these notes.

Holders of the notes we issued in July 2015 will have the right to require us to repurchase all or a portion of their notes upon the occurrence of a fundamental change at a repurchase price equal to 100% of the principal amount of the notes to be repurchased, plus accrued and unpaid interest, if any. In addition, upon conversion of the notes, unless we elect to deliver solely our Class A shares to settle such conversion (other than paying cash in lieu of delivering any fractional share), we will be required to make cash payments in respect of the notes being converted. However, we may not have enough available cash or be able to obtain financing at the time we are required to make repurchases of notes surrendered therefor or pay cash with respect to notes being converted or at their maturity. In addition, our ability to repurchase or to pay cash upon conversions of the notes may be limited by law, regulatory authority or agreements governing our indebtedness. Our failure to repurchase notes at a time when the repurchase is required by the indenture or to pay any cash payable on future conversions of the notes pursuant to the indenture would constitute a default under the indenture governing the issuance of the notes. A fundamental change or a default under the indenture could also lead to a default under agreements governing our or our subsidiaries' indebtedness. If the repayment of the related indebtedness were to be accelerated after any applicable notice or grace periods, we may not have sufficient funds to repay the indebtedness and repurchase the notes or make cash payments upon conversions thereof.

The conditional conversion feature of the notes we have issued, if triggered, may adversely affect our financial condition and operating results.

The notes we issued in July 2015 have a conditional conversion feature. In the event the conditional conversion feature of the notes is triggered, holders of notes will be entitled to convert the notes at any time during specified periods at their option. If one or more holders elect to convert their notes, unless we elect to satisfy our conversion obligation by delivering solely our Class A shares (other than paying cash in lieu of delivering any fractional share), we would be required to settle a portion or all of our conversion obligation through the payment of cash, which could adversely affect our liquidity. In addition, even if holders do not elect to convert their notes, we could be required under applicable accounting rules to reclassify all or a portion of the outstanding principal of the notes as a current rather than long-term liability, which would result in a material reduction of our net working capital.

The accounting method for convertible debt securities that may be settled in cash, such as the notes we issued in July 2015, could have a material effect on our reported financial results.

FASB ASC Subtopic 470-20 ("FASB ASC 470-20"), Debt with Conversion and Other Options, requires an entity to separately account for the liability and equity components of convertible debt instruments (such as the notes) that may be settled entirely or partially in cash upon conversion in a manner that reflects the issuer's non-convertible debt interest rate. Accordingly, the equity component of the notes we issued in July 2015 was required to be included in the additional paid-in capital section of shareholders' equity on our consolidated balance sheet at the issuance date, and the value of the equity component is treated as a discount for purposes of accounting for the debt component of the notes. As a result, we are required to recognize a greater amount of non-cash interest expense in our consolidated income statements in the current and future periods presented as a result of the amortization of the discounted carrying value of the notes to their principal amount over the term of the notes. We may report lower net income (or greater net losses) in our consolidated financial results because FASB ASC 470-20 requires interest to include both the current period's amortization of the discount and the instrument's cash interest coupon. This could adversely affect our reported or future consolidated financial results, the trading price of our Class A shares and the trading price of the notes.

Provisions in the indenture for the notes we issued in July 2015 may deter or prevent a business combination that may be favorable to investors.

If a fundamental change occurs prior to the maturity date of the notes we issued in July 2015, holders of the notes will have the right, at their option, to require us to repurchase all or a portion of their notes. In addition, if a make-whole fundamental change occurs prior to the maturity date of the notes, we will in some cases be required to increase the conversion rate for a holder that elects to convert its notes in connection with such make-whole fundamental change. Furthermore, the indenture for the notes prohibits us from engaging in certain mergers or acquisitions unless, among other things, the surviving entity assumes our obligations under the notes and the indenture. These and other provisions in the indenture for such notes could deter or prevent a third party from acquiring us even when the acquisition may be favorable to investors.

If our subsidiaries default on their obligations under their project-level debt, we may decide to make payments to lenders to prevent foreclosure on the collateral securing the project-level debt, which would, without such payments, cause us to lose certain of our wind power projects.

Our subsidiaries incur various types of debt. Non-recourse debt is repayable solely from the applicable project's revenues and is secured by the project's physical assets, major contracts, cash accounts and, in many cases, our ownership interest in the project subsidiary. Limited recourse debt is debt where we have provided a limited guarantee, and recourse debt is debt where we have provided a full guarantee, which means if our subsidiaries default on these obligations, we will be liable directly to those lenders, although in the case of limited recourse debt only to the extent of our limited recourse obligations. To satisfy these obligations, we may be required to use amounts distributed by our other subsidiaries as well as other sources of available cash, reducing our cash available to execute our business plan and pay dividends to holders of our Class A shares. In addition, if our subsidiaries default on their obligations under non-recourse financing agreements, we may decide to make payments to prevent the lenders of these subsidiaries from foreclosing on the relevant collateral. Such a foreclosure would result in our losing our ownership interest in the subsidiary or in some or all of its assets. The loss of our ownership interest in one or more of our subsidiaries or some or all of their assets could have a material adverse effect on our business, financial condition and results of operations and, in turn, on our cash available for distribution.

We are subject to indemnity obligations.

We provide a variety of indemnities in the ordinary course of business to contractual counterparties and to our lenders and other financial partners. For example, the Hatchet Ridge indemnity indemnifies MetLife Capital, Limited Partnership ("MetLife"), the owner participant, under the Hatchet Ridge Wind Lease Financing against certain tax losses. In addition, we have entered into equity partnership agreements in connection with four of our projects which also provide for specific allocations in certain circumstances.

In addition, although we primarily rely on limited recourse or non-recourse financing at our project-level entities we sometimes provide specific indemnities to support such financings. For example, some of our subsidiaries in the United States had obtained construction bridge loans to finance a portion of project construction costs, and in certain cases, such loans were secured by the ITC cash grant proceeds received from the U.S. Treasury. We have assumed certain indemnities that were originally provided by Pattern Development to certain of these bridge lenders and other on-going term lenders in the event that the ITC cash grant is recaptured by the U.S. Treasury, in whole or in part. The cash grant indemnities are in effect for five years from the date the relevant project commences commercial operations. If, for any of those subsidiaries which received the ITC cash grant, the ITC cash grant is recaptured, in whole or in part, we may be required to make payments under the indemnities to prevent the lenders of those subsidiaries from foreclosing on the relevant project collateral. Payment by us under a cash grant indemnity could have a material adverse effect on our business, financial condition and results of operations and, in turn, on our cash available for distribution.

Our failure to pay any of these indemnities would enable the applicable project lenders to foreclose on the project collateral. The payments we may be obligated to make pursuant to these indemnities could have a material adverse effect on our business, financial condition and results of operations and, in turn, on our cash available for distribution. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and

Capital Resources-Description of Credit Agreements" and "-Tax Equity Partnership Agreements.”

Our hedging activities may not adequately manage our exposure to commodity and financial risk, which could result in significant losses or require us to use cash collateral to meet margin requirements, each of which could have a material adverse effect on our business, financial condition, results of operations and liquidity, which could impair our ability to execute favorable financial hedges in the future.

Certain of the electricity we generate is sold on the open market at spot-market prices. In order to stabilize all or a portion of the revenue from such sales, we have entered, and may in the future enter, into financial swaps, day-ahead sales transaction or other hedging arrangements. We may acquire additional assets in the future with similar hedging agreements. In an effort to stabilize our revenue from electricity sales from these projects, we evaluate the electricity sale options for each of our projects, including the appropriateness of entering into a PPA, a physical sale, a financial swap, or combination of these arrangements. If we sell our electricity into an ISO market without a PPA, we may enter into a physical sale or financial swap to stabilize all or a portion of our estimated revenue stream. Under the term of our existing physical sales, we are obligated to physically deliver electricity to a common delivery point. Under these arrangements, we sell the electricity produced at our facility to the ISO at the project node and buy energy at the common delivery point to meet the delivery obligations under the physical sale. The delivery obligations under the physical sale are for specified volumes in each hour for an overall quantity that we estimate we are highly likely to produce. Under the terms of our existing financial swaps, we are not obligated to physically deliver or purchase electricity. Instead, we receive payments for specified quantities of electricity based on a fixed price and are obligated to pay our counterparty the real time market price for the same quantities of electricity. These financial swaps cover quantities of electricity that we estimate we are highly likely to produce. Gains or losses under the physical sales and financial swaps are designed to be offset by decreases or increases in our revenues from real time market sales of electricity in liquid ISO markets. However, the actual amount of electricity we generate from operations may be materially different from our estimates for a variety of reasons, including variable wind conditions and wind turbine availability. If a project does not generate the volume of electricity covered by the associated physical sale or financial swap contract, we could incur significant losses if electricity prices in the market rise substantially above the fixed price provided for in the physical sale or financial swap. If a project generates more electricity than is contracted in the physical sale or financial swap, the excess production will not be hedged and the related revenues will be exposed to market price fluctuations.

We would also incur financial losses as a result of adverse changes in the mark-to-market values of the financial swaps or if the counterparties to our hedging contracts fail to make payments when due. We could also experience a reduction in cash flow if we are required to post margin in the form of cash collateral to secure our delivery or payment obligations under these hedging agreements. We are not currently required to post cash collateral or issue letters of credit to backstop our obligations under our hedging arrangements after commercial operation has been achieved, but we may be required to do so in the future. However, if we were required to do so, our available cash or available borrowing capacity under the credit facilities under which these letters of credit are issued would be correspondingly reduced.

We enter into PPAs when we sell our electricity into markets other than deregulated ISO markets or where we believe it is otherwise advisable. Under a PPA, we contract to sell all or a fixed proportion of the electricity generated by one of our projects, sometimes bundled with RECs and capacity or other environmental attributes, to a power purchaser which is often a utility or large commercial entity. We do this to stabilize our revenues from that project. We are exposed to the risk that the power purchaser will fail to perform under a PPA, with the result that we will have to sell our electricity at the market price sometime in the future, which could be substantially lower than the price provided in the applicable PPA. In most instances, we also commit to sell minimum levels of generation. If the project generates less than the committed volumes, we may be required to buy the shortfall of electricity (or RECs and other environmental attributes) on the open market or make payments of liquidated damages or be in default under a PPA, which could result in its termination.

We sometimes seek to sell forward a portion of our RECs or other environmental attributes to fix the revenues from those attributes and hedge against future declines in prices of RECs or other environmental attributes. If our projects do not generate the amount of electricity required to earn the RECs or other environmental attributes sold forward or if for any reason the electricity we generate does not produce RECs or other environmental attributes for a particular state, we may be required to make up the shortfall of RECs or other environmental attributes through purchases on the open market or make payments of liquidated damages. Further, current market conditions may limit our ability to hedge sufficient volumes of our anticipated RECs or other environmental attributes, leaving us exposed to the risk of falling prices for RECs or other environmental attributes. Future prices for RECs or other environmental attributes are also subject to the risk that regulatory changes will adversely affect prices.

Risks Related to Ownership of our Class A Shares

We are a holding company with no operations of our own, and we depend on our power projects for cash to fund all of our operations and expenses, including to make dividend payments.

Our operations are conducted almost entirely through our power projects and our ability to generate cash to meet our debt service obligations or to pay dividends is dependent on the earnings and the receipt of funds from our project subsidiaries through distributions or intercompany loans. Our power projects' ability to generate adequate cash depends on a number of factors, including wind conditions, timely completion of any construction projects, the price of electricity, payments by key power purchasers, increased competition, foreign currency exchange rates, compliance with all applicable laws and regulations and other factors. See Item 1A "Risk Factors-Risks Related to Our Projects."

Our ability to declare and pay regular quarterly cash dividends is subject to our obtaining sufficient cash distributions from our project subsidiaries after the payment of operating costs, debt service and other expenses. See Item 5 "Market for Registrant's Common Equity and Related Stockholder Matters-Cash Dividend Policy." We may lack sufficient available cash to pay dividends to holders of our Class A shares due to shortfalls attributable to a number of operational, commercial or other factors, including insufficient cash flow generation by our projects, as well as unknown liabilities, the cost associated with governmental regulation, increases in our operating or general and administrative expenses, principal and interest payments on our and our subsidiaries' outstanding debt, tax expenses, working capital requirements and anticipated cash needs.

Our cash available for distribution to holders of our Class A shares may be reduced as a result of restrictions on our subsidiaries' cash distributions to us under the terms of their indebtedness, or in the event certain specified events occurred under our tax equity arrangements that change the percentage of cash distributions to be made to the tax equity investors.

We intend to declare and pay regular quarterly cash dividends on all of our outstanding Class A shares. However, in any period, our ability to pay dividends to holders of our Class A shares depends on the performance of our subsidiaries and their ability to distribute cash to us as well as all of the other factors discussed under Item 5 "Market for Registrant's Common Equity and Related Stockholder Matters-Cash Dividend Policy." The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness and the provisions existing and future tax equity arrangements.

Restrictions on distributions to us by our subsidiaries under our revolving credit facility and the agreements governing their respective project-level debt could limit our ability to pay anticipated dividends to holders of our Class A shares. These agreements contain financial tests and covenants that our subsidiaries must satisfy prior to making distributions. If any of our subsidiaries is unable to satisfy these restrictions or is otherwise in default under such agreements, it would be prohibited from making distributions to us that could, in turn, limit our ability to pay dividends to holders of our Class A shares. Low wind conditions contributed to two of our projects not satisfying financial tests required to permit distributions during certain quarters of 2015. The terms of our project indebtedness typically require commencement of commercial operations prior to our ability to receive cash distributions from a project. The terms of any such indebtedness also typically include cash management or similar provisions, pursuant to which revenues generated by projects subject to such indebtedness are immediately, or upon the occurrence of certain events, swept into an account for the benefit of the lenders under such debt agreements. As a result, project revenues typically only become available to us after the funding of reserve accounts for, among other things, operations and maintenance expenses, debt service, taxes and insurance at the project level. In some instances, projects may be required to sweep cash to reserve funds intended to mitigate the results of pending litigation or other potentially adverse events.

In addition, the terms of operating agreements for our wind facilities with tax equity investors, which include Panhandle 1, Panhandle 2, Post Rock, Logan's Gap and Amazon Wind Farm Fowler Ridge, generally provide for specified allocations of distributions between the tax equity investors and ourselves which change at a specified point when the tax equity investor has realized a target after tax internal rate of return. In the event this change has not occurred by a targeted date, the tax equity investor begins to receive a greater allocation of distributions until the targeted rate of return has been achieved. In addition, the operating agreements also provide for earlier increases in the percentage of distributable cash to be allocated to the tax equity investors if the project fails to achieve certain defined minimum performance levels that are likely to cause the tax equity investors to not achieve the targeted after tax return by the targeted date and for increases under certain circumstances to match allocations of taxable income that are made to mitigate a negative capital account balance for such tax equity investors. As a result, in the event our share of distributable cash from these projects is changed as a result of one of these events, our distributions from such wind facilities may be less than expected that could, in turn, limit our ability to pay dividends to holders of our Class A shares.

If our projects do not generate sufficient cash available for distribution, we may be required to fund dividends from working capital, borrowings under our revolving credit facility, proceeds from future offerings, the sale of assets or by obtaining other debt or equity financing, which may not be available, any of which could have a material adverse effect on the price of our Class A shares and on our ability to pay dividends at anticipated levels or at all. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Description of Credit Agreements."

Our ability to pay regular dividends on our Class A shares is subject to the discretion of our Board of Directors.

Our Class A stockholders have no contractual or other legal right to dividends. The payment of future dividends on our Class A shares will be at the discretion of our Board of Directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our Board of Directors deems relevant. Our Board of Directors will have the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves could result in a reduction in cash available for distribution to pay dividends on our Class A shares at anticipated levels. Accordingly, we may not be able to make, or may have to reduce or eliminate, the payment of dividends on our Class A shares, which could adversely affect the market price of our Class A shares.

If we fail to maintain proper and effective internal controls, our ability to produce accurate and timely financial statements could be impaired and investors' views of us could be harmed.

U.S. securities laws require, among other things, that we maintain effective internal control over financial reporting and disclosure controls and procedures. We must perform system and process evaluation and testing of our internal control over financial reporting to allow management to report on the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act. If we are not able to comply with these requirements in a timely manner, or if we identify deficiencies in our internal control over financial reporting that are deemed to be material weaknesses, the market price of our shares could decline and we could be subject to sanctions or investigations by the stock exchanges on which we list, the SEC, the Canadian Securities Administrators or other regulatory authorities, which would require additional financial and management resources. While we did not need to file with the SEC any amendments to our quarterly reports on Form 10-Q during 2015, during 2014, we filed with the SEC amendments to our quarterly reports on Form 10-Q for each of the quarters ended March 31, 2014 and June 30, 2014 to correct errors therein. Management reported material weaknesses in our system of internal control over financial reporting as of March 31, 2014, June 30, 2014 and September 30, 2014 which management believes have since been remedied. Moreover, a number of our transactions, including business combinations and other acquisitions, require complex accounting and significant accounting estimates which can result in errors in the reported amounts of acquired assets or liabilities. Accordingly, additional material weaknesses may occur in the future, and we may be unable to provide holders of our securities with the required financial information in a timely and reliable manner which could subject us to litigation and regulatory enforcement actions.

Even if we conclude, from time to time, that our internal control over financial reporting provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP, because of its inherent limitations, internal control over financial reporting may not prevent or detect fraud or misstatements. This, in turn, could have an adverse impact on trading prices for our Class A shares, and could adversely affect our ability to access the capital markets.

Risks Regarding Our Cash Dividend Policy

While we believe that we will have sufficient available cash to enable us to pay the aggregate dividend on our Class A shares for the year ending December 31, 2016, we may be unable to pay the quarterly dividend or any amount on our Class A shares during these periods or any subsequent period. Holders of our Class A shares have no contractual or other legal right to receive cash dividends from us on a quarterly or other basis and, while we currently intend to at least maintain our current dividend and to grow our business and continue to increase our dividend per Class A share over time, our cash dividend policy is subject to all the risks inherent in our business and may be changed at any time. Some of the reasons for such uncertainties in our stated cash dividend policy include the following factors:

- Our revolving credit facility includes customary affirmative and negative covenants that will subject certain of our project subsidiaries to restrictions on making distributions to us. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Description of Credit Agreements-Revolving Credit Facility." Our subsidiaries are also subject to restrictions on distributions under the agreements governing their respective project-level debt. Additionally, we may incur debt in the future to acquire new power projects, the terms of which will likely require commencement of commercial operations prior to our ability to receive cash distributions from such acquired projects. These agreements also likely will contain financial tests and covenants that our subsidiaries must satisfy prior to making distributions. The current financial tests and covenants applicable to our subsidiaries are described in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Description of Credit Agreements.” If any of our subsidiaries is unable to satisfy these restrictions or is otherwise in default under our financing agreements, it would be prohibited from making distributions to us, which could, in turn, limit our ability to pay dividends to holders of our Class A shares at our intended level or at all. See "-Risks Related to our Financial Activities-Our substantial amount of indebtedness may adversely affect our ability to operate our business and impair our ability to pay dividends."

- Under the terms of operating agreements for our wind facilities with tax equity investors, the share of distributable cash we may receive from these projects may change under certain circumstances, and if these circumstances occurred and were adverse, our distributions from such wind facilities may be less than expected. See "-Our cash available for distribution to holders of our Class A shares may be reduced as a result of restrictions on our subsidiaries' cash distributions to us under the terms of their indebtedness, or in the event certain specified events occurred under our tax equity arrangements that change the percentage of cash distributions to be made to the tax equity investors."
- Our Board of Directors will have the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves would reduce the cash available to pay our dividends.
- We may lack sufficient cash available for distribution to pay our dividends due to operational, commercial or other factors, some of which are outside of our control, including insufficient cash flow generation by our projects, as well as unexpected operating interruptions, insufficient wind resources, legal liabilities, the cost associated with governmental regulation, changes in governmental subsidies or regulations, increases in our operating or selling, general and administrative expenses, principal and interest payments on our and our subsidiaries' outstanding debt, tax expenses, working capital requirements and anticipated cash reserve needs.

We are an SEC foreign issuer under Canadian securities laws and, therefore, are exempt from certain requirements of Canadian securities laws applicable to other Canadian reporting issuers.

Although we are a reporting issuer in Canada, we are an SEC foreign issuer under Canadian securities laws and are exempt from certain Canadian securities laws relating to continuous disclosure obligations and proxy solicitation if we comply with certain reporting requirements applicable in the United States, provided that the relevant documents filed with the SEC are filed in Canada and sent to our Class A stockholders in Canada to the extent and in the manner and within the time required by applicable U.S. requirements. In some cases the disclosure obligations applicable in the United States are different or less onerous than the comparable disclosure requirements applicable in Canada for a Canadian reporting issuer that is not exempt from Canadian disclosure obligations. Therefore, there may be less or different publicly available information about us than would be available if we were a Canadian reporting issuer that is not exempt from such Canadian disclosure obligations.

Pattern Development's general partner and its officers and directors have fiduciary or other obligations to act in the best interests of Pattern Development's owners, which could result in a conflict of interest with us and our stockholders.

Pattern Development holds approximately 23% of our outstanding Class A shares, representing in the aggregate an approximate 23% voting interest in our company. Upon the occurrence of the Conversion Event on December 31, 2014, Pattern Development and the management holders who had previously held our Class B shares became entitled to receive dividends, beginning on January 1, 2015, on these shares which have been converted to Class A shares. We are party to the Management Services Agreement, pursuant to which each of our executive officers (including our Chief Executive Officer) is a shared PEG executive and devotes time to both our company and Pattern Development as needed to conduct our respective businesses. As a result, these shared PEG executives have fiduciary and other duties to Pattern Development. Conflicts of interest may arise in the future between our company (including our stockholders other than Pattern Development) and Pattern Development (and its owners and affiliates). Our directors and executive officers owe fiduciary duties to the holders of our shares. However, Pattern Development's general partner and certain of its officers and directors also have a fiduciary duty to act in the best interest of Pattern Development's limited partners, which interest may differ from or conflict with that of our company and our other stockholders.

Pattern Development's share ownership may limit other stockholders ability to influence corporate matters.

Pattern Development or its affiliates hold approximately 23% of the combined voting power of our shares, and this concentration of voting power may limit other stockholders' ability to influence corporate matters, and as a result, actions may be taken that other stockholders may not view as beneficial. As a result of its ownership in our company, Pattern Development has significant influence over all matters that require approval by our stockholders, including the election of directors, as well as substantial influence over our company, including with respect to decisions relating to our capital structure, issuing additional Class A shares or other equity securities, paying dividends on our Class A shares, incurring additional debt, making acquisitions, selling properties or other assets, merging with other companies and undertaking other extraordinary transactions. In any of these matters, the interests of Pattern Development and its affiliates may differ from or conflict with the interests of our other stockholders.

Certain of our executive officers will continue to have an economic interest in, and all of our executive officers will continue to provide services to Pattern Development, which could result in conflicts of interest.
All of our executive officers provide services to Pattern Development pursuant to the terms of the Management Services Agreement between our company and Pattern Development and, as a result, in some instances, have fiduciary or other obligations to Pattern Development. However, none of our Chief Financial Officer, Chief Investment Officer, or Senior Vice President, Operations receives compensation from, or has an economic interest in, Pattern Development. Additionally, while none of our Chief Executive Officer, Executive Vice President, Business Development, Executive Vice President and General Counsel, Senior Vice President, Fiscal and Administrative Services and Senior Vice President, Engineering and Construction receive compensation from Pattern Development, such officers have economic interests in Pattern Development and, accordingly, the benefit to Pattern Development from a transaction between Pattern Development and our company will proportionately inure to their benefit as holders of economic interests in Pattern Development. Pattern Development is a related party under the applicable securities laws governing related party transactions and, as a result, any material transaction between our company and Pattern Development is subject to our corporate governance guidelines, which require prior approval of any such transaction by the conflicts committee, which is comprised solely of independent members of our Board of Directors. Those of our executive officers who have economic interests in Pattern Development may be conflicted when advising the conflicts committee or otherwise participating in the negotiation or approval of such transactions. These executive officers have significant project- and industry-specific expertise that could prove beneficial to the conflicts committee’s decision-making process and the absence of such strategic guidance could have a material adverse effect on our company’s ability to evaluate any such transaction and, in turn, on our business, financial condition and results of operations.
Riverstone is under no obligation to offer us an opportunity to participate in any business opportunities that it may consider from time to time, including those in the energy industry, and, as a result, Riverstone’s existing and future portfolio companies may compete with us for investment or business opportunities.
Conflicts of interest could arise in the future between us, on the one hand, and Riverstone, including its portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities. Riverstone is a private equity firm in the business of making investments in entities primarily in the energy industry. As a result, Riverstone’s existing and future portfolio companies (other than Pattern Development, which is subject to the Non-Competition Agreement) may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.
Subject to the terms of the Non-Competition Agreement with, and our Purchase Rights granted to us by, Pattern Development, we have expressly renounced any interest or expectancy in, or in being offered an opportunity to participate in, any business opportunity that may be from time to time presented to Riverstone or any of its officers, directors, agents, stockholders, members or partners or business opportunities that such parties participate in or desire to participate in, even if the opportunity is one that we might reasonably have pursued or had the ability or desire to pursue if granted the opportunity to do so, and no such person shall be liable to us for breach of any fiduciary or other duty, as a director or officer or controlling stockholder or otherwise, by reason of the fact that such person pursues or acquires any such business opportunity, directs any such business opportunity to another person or fails to present any such business opportunity, or information regarding any such business opportunity, to us unless, in the case of any such person who is our director or officer, any such business opportunity is expressly offered to such director or officer solely in his or her capacity as our director or officer. Riverstone has advised us that it does not have a formal policy regarding business opportunities presented to the investment funds managed or advised by it and their respective portfolio companies, but Riverstone’s practice has been that any business opportunities may be pursued by any such fund or directed to any such portfolio company except when the business opportunity has been presented to an employee of Riverstone or its affiliates solely in his or her capacity as a director of a portfolio company.
As a result, Riverstone may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which it has invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunities. Further, such businesses may choose

to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Riverstone could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.
Our actual or perceived failure to deal appropriately with conflicts of interest with Pattern Development could damage our reputation, increase our exposure to potential litigation and have a material adverse effect on our business, financial condition and results of operations.
Our conflicts committee is required to review, and make recommendations to the full Board of Directors regarding, any future transactions involving the acquisition of an asset or investment in an opportunity offered to us by Pattern Development to determine

whether the offer is fair and reasonable (including any acquisitions by us of assets of Pattern Development pursuant to our Purchase Rights). However, our establishment of a conflicts committee may not prevent holders of our shares from filing derivative claims against us related to these conflicts of interest and related party transactions. Regardless of the merits of their claims, we may be required to expend significant management time and financial resources on the defense of such claims. Additionally, to the extent we fail to appropriately deal with any such conflicts, it could negatively impact our reputation and ability to raise additional funds and the willingness of counterparties to do business with us, all of which could have a material adverse effect on our business, financial condition and results of operations.

Market interest and foreign exchange rates may have an effect on the value of our Class A shares.

One of the factors that influences the price of our Class A shares will be the effective dividend yield of our Class A shares (i.e., the yield as a percentage of the then market price of our Class A shares) relative to market interest rates. An increase in market interest rates, which are currently at low levels relative to historical rates, may lead prospective purchasers of our Class A shares to expect a higher dividend yield and, our inability to increase our dividend as a result of an increase in borrowing costs, insufficient cash available for distribution or otherwise, could result in selling pressure on, and a decrease in the market price of, our Class A shares as investors seek alternative investments with higher yield. Additionally, we intend to pay a regular quarterly dividend in U.S. dollars and, as a result, to the extent the value of the U.S. dollar dividend decreases relative to Canadian dollars, the market price of our Class A shares in Canada could decrease.

The price of our Class A shares may fluctuate significantly, and stockholders could lose all or part of their investment.

Volatility in the market price of our shares may prevent stockholders from being able to sell their Class A shares at or above the price stockholders paid for their shares. The market price of our Class A shares could fluctuate significantly for various reasons, including: our operating and financial performance and prospects;

- our quarterly or annual results of operations or those of other companies in our industry;
- a change in interest rates or changes in currency exchange rates;
- the public’s reaction to our press releases, our other public announcements and our filings with the Canadian securities regulators and the SEC;
- changes in, or failure to meet, earnings estimates or recommendations by research analysts who track our Class A shares or the stock of other companies in our industry;
- the failure of research analysts to cover our Class A shares;
- strategic actions by us, our power purchasers or our competitors, such as acquisitions or restructurings;
- new laws or regulations or new interpretations of existing laws or regulations applicable to our business;
- changes in accounting standards, policies, guidance, interpretations or principles;
- material litigation or government investigations;
- changes in applicable tax laws;
- changes in general conditions in the United States, Canadian and global economies or financial markets, including those resulting from war, incidents of terrorism or responses to such events;
- changes in key personnel;
- sales of Class A shares by us or members of our management team;
- termination of lock-up agreements with our management team and principal stockholders;
- the granting or exercise of employee stock options;
- volume of trading in our Class A shares; and
- the realization of any risks described under “Risk Factors.”

In addition, volatility in the stock markets has had a significant impact on the market price of securities issued by many companies, including companies in our industry and yieldcos. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our Class A shares could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce the share price of our Class A shares and cause stockholders to lose all or part of their investment. Further, in the past, market fluctuations and price declines in a company's stock have led to securities class action litigation. If such a suit were to arise, it could have a substantial cost and divert our resources regardless of the outcome.

We incur increased costs and demands upon management as a result of complying with the laws and regulations affecting public companies, which could harm our operating results.

As a public company, we incur significant legal, accounting, investor relations and other expenses that we did not incur as a private company, including costs associated with public company reporting requirements. We also have incurred and will incur costs associated with current corporate governance requirements, Section 404 and other provisions of the Sarbanes-Oxley Act and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC, the Canadian Securities Administrators and the stock exchanges on which our Class A shares are traded.

The expenses incurred by public companies for reporting and corporate governance purposes have increased dramatically over the past several years. Greater expenditures may be necessary in the future with the advent of new laws and regulations pertaining to public companies. If we are not able to comply with these requirements in a timely manner, the market price of our Class A shares could decline and we could be subject to sanctions or investigations by the SEC, the Canadian Securities Administrators, the applicable stock exchanges or other regulatory authorities, which would require additional financial and management resources.

As a result of the FPA and FERC's regulations in respect of transfers of control, absent prior authorization by FERC, neither we nor Pattern Development can convey, nor will an investor in our company generally be permitted to obtain, a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, and a violation of this limitation could result in civil or criminal penalties under the FPA and possible further sanctions imposed by FERC under the FPA.

We are a holding company with U.S. operating subsidiaries that are "public utilities" (as defined in the FPA) and, therefore, subject to FERC's jurisdiction under the FPA. As a result, the FPA requires us or Pattern Development, as the case may be, either to (i) obtain prior authorization from FERC to transfer an amount of our voting securities sufficient to convey direct or indirect control over any of our public utility subsidiaries or (ii) qualify for a blanket authorization granted under or an exemption from FERC's regulations in respect of transfers of control. Similar restrictions apply to purchasers of our voting securities who are a "holding company" under PUHCA, in a holding company system that includes a transmitting utility or an electric utility, or an "electric holding company," regardless of whether our voting securities were purchased in our initial public offering, subsequent offerings by us or Pattern Development, in open market transactions or otherwise. A purchaser of our voting securities would be a "holding company" under the PUHCA and an electric holding company if the purchaser acquired direct or indirect control over 10% or more of our voting securities or if FERC otherwise determined that the purchaser could directly or indirectly exercise control over our management or policies (e.g., as a result of contractual board or approval rights). Under the PUHCA, a "public-utility company" is defined to include an "electric utility company," which is any company that owns or operates facilities used for the generation, transmission or distribution of electric energy for sale, and which includes EWGs such as our U.S. operating subsidiaries. Accordingly, absent prior authorization by FERC or an increase to the applicable percentage ownership under a blanket authorization, for the purposes of sell-side transactions by us or Pattern Development and buy-side transactions involving purchasers of our securities that are electric holding companies, no purchaser can acquire 10% or more of our issued and outstanding voting securities. A violation of these regulations by us or Pattern Development, as sellers, or an investor, as a purchaser of our securities, could subject the party in violation to civil or criminal penalties under the FPA, including civil penalties of up to $1 million per day per violation and other possible sanctions imposed by FERC under the FPA.

As a result of the FPA and FERC's regulations in respect of transfers of control, and consistent with the requirements for blanket authorizations granted thereunder or exemptions therefrom, absent prior authorization by FERC, no purchaser of our common shares in the open market, or in subsequent offerings of our voting securities, will be permitted to purchase an amount of our securities that would cause such purchaser and its affiliate and associate companies to collectively hold 10% or more of our voting securities outstanding. Additionally, investors should manage their investment in us in a manner consistent with FERC's regulations in respect of obtaining direct or indirect "control" of our company. Accordingly, absent prior authorization by FERC, investors in our common shares are advised not to acquire a direct and/or indirect voting interest in 10% or more of our issued and outstanding voting securities, whether in connection with an offering by us or Pattern Development or in open market purchases or otherwise.

Provisions of our organizational documents and Delaware law might discourage, delay or prevent a change of control of our company or changes in our management and, as a result, depress the trading price of our Class A shares.

Our amended and restated certificate of incorporation and amended and restated bylaws contain provisions that could discourage, delay or prevent a change in control of our company or changes in our management that the stockholders of our company may deem advantageous. These provisions:

- authorize the issuance of blank check preferred stock that our Board of Directors could issue to increase the number of outstanding shares and to discourage a takeover attempt;
- prohibit our stockholders from calling a special meeting of stockholders;
- prohibit stockholder action by written consent, which requires all stockholder actions to be taken at a meeting of our stockholders;
- provide that the Board of Directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establish advance notice requirements for nominations for election to our Board of Directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

These anti-takeover defenses could discourage, delay or prevent a transaction involving a change in control of our company. These provisions could also discourage proxy contests and make it more difficult for stockholders to elect directors of their choosing and cause us to take corporate actions other than those desired.

Future sales of our shares in the public market could lower our Class A share price, and any additional capital raised by us through the sale of equity or convertible debt securities may dilute stockholders' ownership in us and may adversely affect the market price of our Class A shares.

In February 2015, we completed a follow-on offering of our Class A shares. In total 12,000,000 Class A shares were sold. Of this amount, we issued and sold 7,000,000 Class A shares and Pattern Development, a selling shareholder, sold 5,000,000 of our Class A shares. In addition, in July 2015, we completed another follow-on offering of our Class A shares in which we issued and sold 5,435,000 Class A shares. Concurrently, in July 2015, we issued $225.0 million aggregate principal amount of 4.00% Convertible Senior Notes due 2020. If we sell, or if Pattern Development sells, additional large numbers of our Class A shares, or if we issue a large number of shares of our Class A common stock in connection with future acquisitions, financings, or other circumstances, the market price of our Class A shares could decline significantly. Moreover, the perception in the public market that we or Pattern Development might sell Class A shares could depress the market price of those shares.

In addition, in May 2014, Pattern Development entered into a loan agreement pursuant to which it may pledge our Class A shares owned by it to secure a $100.0 million loan. As of December 31, 2015, substantially all of our Class A shares owned by Pattern Development, approximating 17.0 million Class A shares, have been pledged as security for such loan. If Pattern Development were to default on its obligations under the loan, the lenders would have the right to sell shares to satisfy Pattern Development's obligation. Such an event could cause our stock price to decline. We cannot predict the size of future issuances of our Class A shares or sales of securities convertible into our Class A shares, or the effect, if any, that any such future issuances or sales will have on the market price of our shares. Sales of substantial amounts of our shares (including sales pursuant to Pattern Development's registration rights and shares issued in connection with an acquisition) or securities convertible into our shares, or the perception that such sales could occur, may adversely affect prevailing market prices for our Class A shares.

Item 1B. Unresolved Staff Comments.

None

Item 2. Properties.

Leased Facilities

Our corporate headquarters and executive offices are located in San Francisco, California. Effective January 1, 2016, Pattern Development assigned to us all of Pattern Development's rights, title and interest in its existing San Francisco office lease. Concurrently with the lease assignment, we entered into an extension through 2026 of such San Francisco office lease, and agreed to a future expansion of additional office space. In addition, we conduct business activities from Pattern Development-leased office facilities in Houston, San Diego, Santiago and Toronto, as well as additional Pattern Development newly leased office facilities in San Francisco. In February 2016, we have also signed a lease for new office facilities in Houston effective July 2016, to replace the Pattern Development-leased office facilities in Houston upon the termination of such lease in June 2016. We believe that our existing office facilities are in good condition and suitable for the conduct of our business.

Our Projects

We own interests in 16 operating wind power projects. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement. We expect any project we acquire in the future will be party to a similar agreement, but we may acquire projects with greater levels of uncontracted capacity. We typically finance our wind projects through project entity specific debt secured by each project's assets with no recourse to us.

Operating Projects

Gulf Wind

Gulf Wind is a 283 MW project located in Kenedy County, Texas. The project consists of 118 2.4 MW Mitsubishi MWT95/2.4 turbines and commenced commercial operations in 2009. Pattern Development acquired this operational project in March 2010. On July 28, 2015, we acquired the noncontrolling interests in the Gulf Wind project, resulting in our 100% ownership of the membership interests in the Gulf Wind project. Prior to these acquisitions, Gulf Wind was held by a tax equity partnership with MetLife. We, Pattern Development, and MetLife previously owned approximately 40%, 27% and 33% of Gulf Wind, respectively.

The project is located in the South Zone of the ERCOT market and sells 100% of its power output into the ERCOT market, receiving the locational marginal price, or "LMP." Approximately 58% of the project’s expected annual electricity generation has been hedged under a 10-year fixed-for-floating swap with Morgan Stanley. This financial hedging agreement settles using the South Trading Hub hourly LMP, weighted by the settlement volume in each hour. The project is connected to the Electric Transmission Texas 345 kV transmission system and is entirely on land owned by a single private landowner. Gulf Wind entered into an easement agreement with a single landowner on May 9, 2007 for an initial term of 30 years and with an option to extend for an additional 10 years. The land, which is primarily grassland and dunes, is part of a very large ranch. In addition to our wind operations, the ranch is also used for cattle raising, oil & gas production, and private hunting outings. Due to the afternoon sea breeze effect along the coast, Gulf Wind benefits from an average daily wind production profile that generally follows the typical electricity demand load profile, which is heaviest during the daytime.

Hatchet Ridge

Hatchet Ridge is a 101 MW project located near Burney, California. The project consists of 44 2.3 MW Siemens turbines and commenced commercial operations in December 2010. The project is connected to the PG&E transmission system.

The project sells 100% of its electricity generation, including environmental attributes, to PG&E under a 15-year PPA that expires in 2025. The price under the PPA is a stated price per MWh, adjusted by seasonal time of day multipliers, with no escalation. Hatchet Ridge is required to post performance security in the amount of $21.2 million to secure damages under the PPA. The PPA also contains customary termination and event of default provisions. Under the terms of the PPA, Hatchet Ridge is required to pay liquidated damages for failure to produce a certain amount of energy in each of two consecutive years.

The project is located in Shasta County, California and is entirely on land owned by two private landowners, subject to 30-year wind power ground lease agreements.

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St. Joseph

St. Joseph is a 138 MW project located near St. Joseph, Manitoba, just north of the U.S. border. The project consists of 60 2.3 MW Siemens turbines and commenced commercial operations in April 2011. The project is connected to the Manitoba Hydro transmission system. St. Joseph was the second commercial wind power project, and is the largest, in Manitoba.

The project sells 100% of its electricity generation, including environmental attributes, to Manitoba Hydro under a 27-year PPA that expires in 2039. The price under the PPA is a stated price per MWh at inception of the PPA, with approximately 20% of the stated price escalating annually at the consumer price index for Canada, or "Canadian CPI." The project additionally receives the ecoEnergy federal incentive of C$10/MWh for approximately ten years for up to 423,108 MWh of production per year. Under the PPA, if there is a sale of the project, Manitoba Hydro has a right of first offer to purchase the St. Joseph project for a fixed minimum purchase price on terms specified by us. In addition to customary termination and event of default provisions, the PPA will terminate upon the exercise by Manitoba Hydro of its right of first offer to purchase the St. Joseph project, and St. Joseph will trigger an event of default, if after the first three contract years, it fails to supply at least 80% of certain minimal energy obligations for two consecutive years.

The project is located on approximately 125 square kilometers of agricultural land in the Rural Municipalities of Montcalm and Rhineland, Province of Manitoba. The project is constructed on privately owned lands pursuant to right-of-way agreements with 64 private landowners, with 40-year terms and all on substantially the same form of agreement covering all of turbine sites, collection lines, roads and an operations and maintenance building for the project. In addition, the project purchased a small parcel of property for the project substation.

Spring Valley

Spring Valley is a 152 MW project located in White Pine County, Nevada. The project consists of 66 2.3 MW Siemens turbines and commenced commercial operations in August 2012. The project is connected to the NV Energy transmission system. Spring Valley was Nevada's first commercial wind power project.

The project sells 100% of its electricity generation, including environmental attributes, to NV Energy, under a 20-year PPA that expires in 2032. The price under the PPA is a stated price per MWh escalating at 1.0% per year. Spring Valley is required to reimburse NV Energy for replacement costs for any annual energy shortfall and post operating security in the amount of $6.3 million for the performance of its obligations under the PPA. The PPA also contains customary termination and event of default provisions.

The project is located in White Pine County, Nevada on federal land administered by the Bureau of Land Management. Spring Valley was granted a right-of-way from the Bureau of Land Management with a 30-year term, which terminates on December 31, 2040.

Santa Isabel

Santa Isabel is a 101 MW project located on the south coast of Puerto Rico. The project consists of 44 2.3 MW Siemens turbines and commenced commercial operations during the fourth quarter of 2012. The project is connected to the Puerto Rico Electric Power Authority, or "PREPA," transmission system. Santa Isabel is Puerto Rico's first commercial wind power project and is reflective of the Puerto Rican government's efforts to diversify its energy sources away from fossil fuels by fostering local renewable energy projects.

The project sells 100% of its electricity generation including environmental attributes to PREPA under a 20-year PPA, expiring in 2030, with automatic 5-year extensions unless terminated at the end of any term or extension by us, and PREPA may terminate after year 25 if there is a liquid spot-market for electricity or the agreement has been in effect for 30 years. Under the PPA, PREPA has agreed to purchase electricity from us subject to a 75 MW per hour cap, with such cap increasing to 95 MW during certain hours of certain months. If the project is capable of generating electricity in excess of the applicable cap, PREPA has the option, but not the obligation, to purchase any such surplus electricity actually generated at the PPA price. The price for energy under the PPA and the price for RECs under a separate purchase agreement are both a stated price per MWh. Each price escalates at 1.5% per year. In the case that project electricity generation exceeds a threshold multiple of contractual electricity generation in a given year, the price for energy under the PPA reduces until output drops below contractual output for such year. Santa Isabel is required to post operating security in the amount of $3.0 million for the performance of its obligations under the PPA. In addition to customary termination and event of default provisions, the PPA may terminate if Santa Isabel fails to generate a threshold energy output during any 12 consecutive months.

The project is located on land owned by the Puerto Rico Land Authority, or "PRLA," which is actively farmed by private operations under land leases with the PRLA. The project entered into a deed of lease, easements and restrictive covenants with the PRLA on October 6, 2011, with a 30-year initial term, together with up to 45 years in renewal options, comprising substantially all project infrastructure, including all turbine sites, collection lines, roads, substation and operations and maintenance buildings for the project. The project also has entered into transmission line leases for the transmission line corridor from the project substation to the point of interconnection with PREPA with four private landowners.

Ocotillo

Ocotillo is a 265 MW project located in western Imperial County, California. The project consists of 112 2.37 MW Siemens turbines. We initially commenced commercial operations on 223 MW of Ocotillo’s electricity generating capacity during the fourth quarter of 2012 and commenced commercial operations on the remaining 42 MW of electricity generating capacity from Ocotillo’s additional 18 turbines in July 2013. The project connects to the San Diego Gas & Electric, or "SDG&E," 500 kV transmission system and has a large generator interconnection agreement with SDG&E and CAISO.

The project sells 100% of its electricity generation, including capacity and environmental attributes, to SDG&E under a 20-year PPA. The PPA has a stated price per MWh with no escalation. Ocotillo is required to post performance security in the amount of $26.7 million to secure damages. The PPA also contains customary termination and event of default provisions. Under the PPA, Ocotillo is required to pay liquidated damages for failure to produce a certain amount of energy in the two previous years.

Ocotillo is the subject of active lawsuits brought by a variety of project opponents. See Item 3 "Legal Proceedings."

The project is located on approximately 12,500 acres in Imperial County, California and is almost entirely on federal land administered by Bureau of Land Management. The project was granted a right-of-way from the Bureau of Land Management with a 30-year term, which terminates on December 31, 2041. All the project’s turbine sites, a substation and an operations and maintenance building are located on land administered by the Bureau of Land Management. The project has entered into collection and distribution line easements with two private landowners for a portion of the underground collection system. In addition, the project has purchased a small parcel of land for a portion of the underground collection system. The project also has a lease agreement in place with a private landowner for an additional 26 acres of private land.

South Kent

South Kent is a 270 MW project located in the municipality of Chatham-Kent in southern Ontario and consists of 124 2.3 MW class Siemens turbines. The project connects to the Hydro One Networks, Inc., or "HONI," 230 kV transmission system at the existing Chatham switching station. The South Kent project commenced construction in the first quarter of 2013 and commenced commercial operations in March 2014.

The project sells 100% of its electricity generation, including environmental attributes, to the IESO under a 20-year PPA. The PPA has a stated price, which indexes at Canadian CPI from September 2009 until December 31 of the year prior to commencement of commercial operations which was in March 2014; thereafter 20% of the PPA price escalates at Canadian CPI. The PPA was granted in connection with the Green Energy Investment Agreement, an agreement among Samsung, Korea Electric Power Corporation and the Province of Ontario. This agreement supports growth in domestic renewable energy through both jobs creation and support of wind power and solar power projects. The PPA also provides for compensation by the IESO for certain energy the project is unable to produce due to curtailments directed by the grid operator.

The project is a 50/50 joint venture between us and Samsung. Samsung has customary rights to purchase our interest in South Kent upon any subsequent sale of the project by us.

The project is located on approximately 165 distinct private land parcels and includes a conglomeration of multiple acquired wind power projects and greenfield acquired lands. The project has renegotiated and standardized each of the land agreements that were assumed along with the acquired projects. All land parcels containing project infrastructure are contracted under registered right-of-way agreements, providing for real estate interests in favor of the project in the form of easements-in-gross in respect of each land parcel, enforceable for a term of not less than 40 years.

The project’s generation tie to the HONI transmission system is located on real estate comprised primarily of 26 kilometers of an abandoned railway corridor running across the project area, together with additional private land transmission easements.

El Arrayán

El Arrayán is a 115 MW project located on the coast of Chile, near Ovalle in the Fourth Region. We owned a 31.5% indirect interest in El Arrayán prior to acquiring an additional 38.5% interest in order to obtain majority control (70%) of the project, as a part of our growth strategy. The project consists of 50 2.3 MW Siemens turbines and began commercial operations in June 2014. The project is connected to the Sistema Interconectado Central's, or "SIC," 220kV transmission system. El Arrayán is Chile's largest commercial wind power project and is reflective of the Chilean government's efforts to diversify its energy sources away from fossil fuels by fostering local renewable energy projects.

The project sells electricity generation into the Chilean spot-market at the prevailing market price at the time of sale. Approximately 70% of the project's expected output has been hedged under a 20-year fixed-for-floating swap with Minera Los Pelambres, or "MLP," one of the world's largest copper mines. The hedge price escalates at 1.5% annually. The hedge includes the transfer of environmental attributes to MLP. The project has also entered into a 20-year PPA with MLP to acquire from the market and supply MLP with up to 40 MW of capacity and related energy. This PPA is purely a cost pass-through arrangement intended to firm the power supplied to MLP, under which MLP will reimburse the project for amounts supplied. MLP is a subsidiary of AMSA, who owns a 30% noncontrolling interest in the project.

The project is located on coastal land and is leased from a single landowner. The land is not presently used for any residential or other commercial purposes. The project entered into a lease agreement with Sociedad Inmobiliaria Correa y Compańía Limitada on January 4, 2012, with a 30-year term covering the project site and comprising all of the turbine sites, collection lines, roads, a project substation and an operations and maintenance building for the project. The project has entered into agreements with four private landowners for the approximately 22 kilometer transmission line corridor from the project substation to the point of interconnection with Transelec S.A.

Mining rights are entirely separate from surface rights in Chile and must be controlled in order to prevent interference by a third party. The project has mining rights for all of its infrastructure including the turbines and operational facilities, the interconnecting transmission line and all main roads which are not public.

Panhandle 1

Panhandle 1 is a 218 MW project located in the Texas Panhandle, in Carson County, Texas. The project consists of 118 GE 1.85 MW turbines and commenced commercial operations in June 2014.

The project is located in the West zone of the ERCOT market and sells 100% of its power output into the ERCOT market, receiving the LMP from ERCOT for its actual generation. Approximately 80% of the project's expected annual electricity generation has been hedged under a physical power hedge with an affiliate of Citigroup with a tenor in excess of ten years. This hedging agreement settles using the North Trading Hub hourly LMP weighted by the settlement volume in each hour. The hourly notional settlement volume varies to match the project's expected hourly production profile. Panhandle 1's obligations under the hedge are secured by a first priority lien on substantially all of the assets of Panhandle 1 and a first priority lien on the membership interests in the project entity.

The project is connected to the ERCOT grid via a new 345kV transmission line owned by Cross Texas Transmission, LLC, which is part of the Texas Competitive Renewable Energy Zone ("CREZ") program. The project is located on private land pursuant to 40-year easement agreements with approximately 30 private landowners, all of which agreements are in substantially the same form. The project's operations and maintenance building is shared with the neighboring Panhandle 2 project.

Panhandle 2

Panhandle 2 is a 182 MW project located in the Texas Panhandle in Carson County, Texas. The project consists of 79 2.3 MW Siemens turbines and commenced commercial operations in November 2014.

The project is located in the West zone of the ERCOT market and sells 100% of its power output into the ERCOT market, receiving the LMP from ERCOT for its actual generation. Approximately 80% of the project's expected annual electricity generation has been hedged under a physical power hedge with an affiliate of Morgan Stanley with a tenor in excess of ten years. This hedging agreement settles using the North Trading Hub hourly LMP weighted by the settlement volume in each hour. The hourly notional settlement volume varies to match the project's hourly average production profile. Panhandle 2's obligations under the hedge are secured by a first priority lien on substantially all of the assets of Panhandle 2 and a first priority lien on the membership interests in the project entity.

The project is connected to the ERCOT grid via a new 345kV transmission line owned by Cross Texas Transmission, LLC, which is part of the Texas CREZ program. The project is located on private land pursuant to 40-year easement agreements with approximately 15 private landowners, all of which agreements are in substantially the same form. The project's operations and maintenance building is shared with the neighboring Panhandle 1 project.

Grand

Grand is a 149 MW project located in Haldimand County in southern Ontario, and consists of 67 2.3 MW class Siemens turbines. The project is connected to the HONI transmission system via a shared transmission line that is co-owned with an adjacent solar facility. The project has executed a co-ownership agreement with that solar facility that ensures unimpeded access across the shared transmission line to the HONI system. The Grand project commenced construction in the third quarter of 2013 and commenced commercial operations in December 2014.

The project sells 100% of its electricity generation, including environmental attributes, to the IESO under a 20-year PPA. The PPA has a stated price, which indexes at Canadian CPI from September 2009 until December 31 of the year prior to commencement of commercial operations which was in the fourth quarter of 2014; thereafter 20% of the PPA price escalates at Canadian CPI. The PPA was granted in connection with the Green Energy Investment Agreement, an agreement among Samsung, Korea Electric Power Corporation and the Province of Ontario. This agreement supports growth in domestic renewable energy through both jobs creation and support of wind power and solar power projects. The PPA also provides for compensation by the IESO for certain energy the project is unable to produce due to curtailments directed by the grid operator.

The project is a 45/45/10 joint venture between us, Samsung and the Six Nations. Samsung has customary rights to purchase our interest in Grand upon any subsequent sale of the project by us.

The project occupies a combination of leased privately owned farm properties (as to 58 turbines) and leased lands owned and managed by Ontario Infrastructure and Lands Corporation ("OILC") (as to 9 turbines). All parcels containing project infrastructure are governed by the terms of standardized leases and easements with terms of a minimum of 45 years (including all renewal periods). The project’s transmission line is located primarily on a major public road allowance pursuant to a Road Use Agreement (with a registered easement).

The transmission facilities also include a collector substation located on OILC lands, underground transition stations located on two private properties and an interconnection station located on lands controlled by a local aggregate producer. Collector lines and ancillary project infrastructure are located within a public road allowance throughout Haldimand County pursuant to a Road Use Agreement with the municipality.

Logan’s Gap

Logan’s Gap is a 200 MW project in Comanche County, Texas. The project consists of 87 Siemens 2.3 MW wind turbines. Located near the Dallas-Fort Worth area, Logan’s Gap is our fourth wind project in Texas, serving three different regions throughout the state.

The project is located in the North zone of the ERCOT market and sells 100% of its power output into the ERCOT market, receiving the LMP from ERCOT for its actual generation. Approximately 58% of the expected output of the project is sold under a 10-year power purchase agreement with Wal-Mart Stores, Inc. An additional 17% of the project’s expected annual electricity generation has been hedged under a 13-year fixed-for-floating physical power hedge with an affiliate of the Bank of America Merrill Lynch. Both the power purchase agreement and the physical hedge settle using the North Trading Hub hourly LMP weighted by the settlement volume in each hour. The hourly notional settlement varies to match the project’s expected hourly production profile. Logan’s Gap’s obligations under the PPA are secured by a Letter of Credit and the obligations under the hedge are secured by a first priority lien on substantially all of the assets of Logan’s Gap and a first priority lien on the membership interests in the project entity.

The project connects to Oncor’s 138kV Comanche-Zephyr line, which crosses the project site and supplies power to the Dallas-Fort Worth area. The project is located on private land pursuant to 30-year easement agreements with approximately 15 private landowners, all of which agreements are in substantially the same form.

Amazon Wind Farm Fowler Ridge

Amazon Wind Farm Fowler Ridge is a 150 MW project located in Benton County, Indiana. The project consists of 65 2.3 MW Siemens turbines and commenced commercial operations in December 2015.

The project has a 13-year power purchase agreement with wholly-owned subsidiary of Amazon Web Services, or "Amazon", that began in January 2016. During the first month of the PPA, 50% of the production will be sold to Amazon. This amount will increase over an 18 month period until 100% of the production is being purchased by Amazon. During this period, the balance of the production will be sold in the PJM wholesale market.

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The project is connected to the PJM grid via common transmission facilities that are shared with Fowler Ridge phases I, II and III to an existing 345kV transmission switching station at the Indiana Michigan Dequine Switching Station, where the facility will interconnect to the connecting utility's 345 kV transmission line, and as further specified in the generator interconnection agreement between the independent system operator, the connecting utility and the seller. The common transmission facilities are owned by all four phases of the Fowler Ridge Wind Project and are operated and maintained by British Petroleum. The project is located on private land pursuant to 30-year easement agreements with approximately 69 private landowners, all of which agreements are in substantially the same form.

Post Rock

Post Rock is a 201 MW project located in Ellsworth and Lincoln Counties, Kansas. The project consists of 134 1.5 MW GE turbines and commenced commercial operations in October 2012. We acquired the project from the original developer on May 15, 2015.

The project sells 100% of its power output under a long-term power purchase agreement with Westar Energy. Westar Energy has a right to extend the agreement by five years without any change in price.

The project includes a 230 KV transmission line, which runs approximately 31 miles from the project substation to the point of interconnection at the Midwest Energy Rice County Substation. The project land is controlled by a 20-year standard lease renewal term option beyond the initial 40 years and pursuant to an easement agreement with 100 landowners for royalty payments and participation payments.

Lost Creek

Lost Creek is a 150 MW project located in King City, Missouri. The project consists of 100 1.5 MW GE turbines and commenced commercial operations in May 2010. We acquired the project from the original developer on May 15, 2015.

The project sells 100% of its power output under a long-term power purchase agreement with Associated Electric Cooperative Incorporated ("AECI"). AECI has the option to extend the term to a mutually agreeable date at a price equal to 95% of the prevailing market price, as determined by a third party consultant, or enter into exclusive negotiations to determine a new rate.

This project interconnects to a new 161 kV transmission line that is owned and operated by NW Electric Cooperative, a member of AECI. The project land is controlled by a 25-year standard lease term and pursuant to easement agreements with 59 landowners.

K2

K2 is a 270 MW project located in Goderich, Ontario. The project consists of 140 2.3 MW class Siemens turbines and commenced commercial operations in May 2015.

The project sells 100% of its power output and environment attributes under a 20-year power purchase agreement with the IESO. The PPA has a stated price, which indexes at Canadian CPI from September 2009 until December 31 of the year prior to commencement of commercial operations which was in May 2015; thereafter 20% of the PPA price escalates at Canadian CPI. The PPA was granted in connection with the Green Energy Investment Agreement, an agreement among Samsung, Korea Electric Power Corporation and the Province of Ontario. This agreement supports growth in domestic renewable energy through both jobs creation and support of wind power and solar power projects. The PPA also provides for compensation by the IESO for certain energy the project is unable to produce due to curtailments directed by the grid operator.

The project is located on private land pursuant to 30-year easement agreements with approximately 82 private landowners, all of which agreements are in substantially the same form.

Item 3. Legal Proceedings.

On April 25, 2012, the County of Imperial certified a Final Environmental Impact Report and Environmental Impact Statement, and entered into a project implementation agreement, or "County Agreement," regarding the Ocotillo project. On May 11, 2012, the Bureau of Land Management issued a Record of Decision, or "ROD," and granted a right-of-way relating to the Ocotillo project. The ROD, right-of-way and County Agreement, which we collectively refer to as the "Approvals," allow Ocotillo to construct the project. Following issuance of the Approvals, a total of six lawsuits, including one in state court, were filed by various local opposition groups alleging that the Approvals were not appropriately issued. In three lawsuits, the plaintiffs sought preliminary equitable relief to enjoin

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the construction of the project while the court decided the claims, and in each instance, the court rejected such request and allowed project construction to continue. The project has since been completed and has achieved commercial operations. In addition, the courts had subsequently dismissed all of the lawsuits. The time to appeal two of the dismissed cases has lapsed. The appeal of the state lawsuit had been abandoned. Three of the dismissals were appealed to the U.S. Court of Appeals for the Ninth Circuit. Oral arguments were heard in November 2015, and the appeals court has subsequently issued a decision in one of the appeals in which it affirmed the decision of the lower court.

In addition, during the third quarter of 2015, rights to appeal prior decisions granting the Renewable Energy Approval, or "REA," under Ontario's Environmental Protection Act for our K2 facility were exhausted without further appeal. As a result, a stay of a previously filed civil suit against the K2 facility pending final determination of the REA was lifted, allowing such suit to move forward if the claimants so choose to continue such suit. Such civil suit had claimed, among other things, nuisance based on both the construction and operation of the facility.

We do not believe these proceedings will have a material adverse effect on our business, financial position or liquidity based on the information currently available to us, principally because attempts to enjoin the construction of the project have failed, and, subject to the pending appeals described above, the actively adjudicated lawsuits have all been dismissed or appeals exhausted. We believe, but can give no assurance, that the remaining litigation will ultimately be resolved favorably to the respective project.

Other Proceedings

We are also subject, from time to time, to various other routine legal proceedings and claims arising out of the normal course of business. These proceedings primarily involve claims from landowners related to calculation of land royalties and warranty claims we initiate against equipment suppliers. The outcome of these legal proceedings and claims cannot be predicted with certainty. Nevertheless, we believe the outcome of any of such currently existing proceedings, even if determined adversely, would not have a material adverse effect on our financial condition or results of operations.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

Our Class A common stock began trading on September 27, 2013 on the NASDAQ Global Market under the trading symbol "PEGI" and on the Toronto Stock Exchange ("TSX") under the trading symbol "PEG." In July 2015, our stock was moved to the NASDAQ Global Select Market. On February 24, 2016, the last reported sale price of our Class A common stock on the NASDAQ Global Select Market was $16.40 per share and on the TSX was C$22.47 per share.

The following table sets forth, for the periods indicated, the high and low sales prices for our Class A common stock on the NASDAQ Global Select Market:

	2015		2014	
	High	Low	High	Low
Fourth Quarter	$24.09	$16.96	$32.03	$22.68
Third Quarter	$29.81	$18.18	$34.51	$29.61
Second Quarter	$32.00	$27.13	$34.15	$24.35
First Quarter	$31.20	$24.13	$31.79	$25.82

The following table sets forth, for the periods indicated, the range of high and low sales prices for our Class A common stock on the TSX:

	2015				2014			
	High		Low		High		Low	
Fourth Quarter	C$	31.58	C$	22.79	C$	35.73	C$	26.63
Third Quarter	C$	38.66	C$	24.75	C$	36.70	C$	32.51
Second Quarter	C$	38.20	C$	32.96	C$	35.39	C$	26.82
First Quarter	C$	38.50	C$	28.81	C$	34.99	C$	26.64

On July 28, 2015, we completed an underwritten public offering of our Class A common stock. In total, 5,435,000 shares of our Class A common stock were sold. We generated net proceeds of approximately $120.8 million after deduction of underwriting discounts, commissions and transaction expenses. As a result, Pattern Development's interest in us was diluted from approximately 25% to 23%.

On February 9, 2015, we completed a follow-on offering of our Class A common stock, under which 12,000,000 shares of Class A common stock were sold. Of this, we issued and sold 7,000,000 shares of our Class A common stock, and Pattern Development sold 5,000,000 shares of its holdings in our Class A common stock. We received proceeds of approximately $196.2 million, net of underwriting discounts and commissions and offering expenses. We did not receive any proceeds from the sale of shares sold by Pattern Development. As a result of this transaction, Pattern Development's ownership interest in us decreased to approximately 25%, following which it was no longer entitled to certain approval rights pursuant to the Shareholder Approval Rights Agreement dated October 2, 2013, and such agreement expired.

Holders of Record

Because many of our shares of Class A common stock are held by brokers and other institutions on behalf of stockholders, we are unable to estimate the total number of stockholders represented by these record holders. As of February 24, 2016, there were approximately 10 stockholders of record of our Class A common stock.

Stock performance chart

This performance graph shall not be deemed “soliciting material” or to be “filed” with the SEC for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or the "Exchange Act," or otherwise subject to the liabilities under that Section, and shall not be deemed to be incorporated by reference into any filing of Pattern Energy under the Securities Act of 1933, as amended, or the "Securities Act."

The following graph shows a comparison from September 27, 2013 (the date our Class A common stock commenced trading on the NASDAQ Global Market) through December 31, 2015 of the cumulative total stockholder return for our Class A common stock, the NASDAQ Composite Index (“NASDAQ Composite”) and the Bloomberg Global Wind Index. The graph assumes that $100 was invested at the market close on September 27, 2013 in the Class A common stock of Pattern Energy, the NASDAQ Composite and the Bloomberg Global Wind Index and also assumes reinvestments of dividends. The stock price performance of the following graph is not necessarily indicative of future stock price performance.

Cash Dividend to Investors

We intend to pay regular quarterly dividends in U.S. dollars to holders of our Class A shares. The following table sets forth the dividends declared on shares of Class A common stock for the periods indicated. On November 26, 2013, we announced the initiation of a quarterly dividend on our Class A common stock. On February 24, 2016, we increased our dividend to $0.3810 per Class A share, or $1.524 per Class A share on an annualized basis, commencing with respect to dividends paid on April 29, 2016 to holders of record on March 31, 2016.

	Dividends Declared
2016	
First Quarter	$0.3810
2015	
Fourth Quarter	$0.3720
Third Quarter	$0.3630
Second Quarter	$0.3520
First Quarter	$0.3420
2014	
Fourth Quarter	$0.3350
Third Quarter	$0.3280
Second Quarter	$0.3220
First Quarter	$0.3125

We have established our quarterly dividend level based on a targeted cash available for distribution payout ratio of 80% both prior to and following the Conversion Event, after considering the annual cash available for distribution that we expect our projects will be able to generate following the commencement of commercial operations at all of our construction projects and with due regard to retaining a portion of the cash available for distribution to grow our business. We intend to grow our business primarily through the acquisition of operational and construction-ready power projects, which, we believe, will facilitate the growth of our cash available for distribution and enable us to increase our dividend per Class A share over time. However, the determination of the amount of cash dividends to be paid to holders of our Class A shares will be made by our Board of Directors and will depend upon our financial condition, results of operations, cash flow, long-term prospects and any other matters that our Board of Directors deem relevant. See Item 1A "Risk Factors—Risks Related to Ownership of our Class A Shares—Risks Regarding our Cash Dividend Policy."

We expect to pay a quarterly dividend on or about the 30th day following each fiscal quarter to holders of record of our Class A shares on the last day of such quarter.

Our cash available for distribution is likely to fluctuate from quarter to quarter, perhaps significantly, as a result of variability in wind conditions and other factors. Accordingly, during quarters in which we generate cash available for distribution in excess of the amount required to pay our stated quarterly dividend, we may reserve a portion of the excess to fund dividends in future quarters. In addition, we may use sources of cash not included in our calculation of cash available for distribution, such as certain net cash provided by financing and investing activities, to pay dividends to holders of our Class A shares in quarters in which we do not generate sufficient cash available for distribution to fund our stated quarterly dividend. Although these other sources of cash may be substantial and available to fund a dividend payment in a particular period, we exclude these items from our calculation of cash available for distribution because we consider them non-recurring or otherwise not representative of the operating cash flows we typically expect to generate. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Metrics—Cash Available for Distribution."

Repurchase of Equity Securities

The table below provides information with respect to repurchases of our Class A common stock during the fourth quarter ended December 31, 2015. All shares were tendered to us in satisfaction of employee tax withholding obligations upon the vesting of restricted stock grants under our 2013 Equity Incentive Award Plan. We currently do not have a stock repurchase plan in place.

Period	Total Number of Shares Purchased	Average Price Paid Per Share
10/1/15-10/31/15	323	$23.39
11/1/15-11/30/15	323	$18.23
12/1/15-12/31/15	27,163	$18.99
	27,809	$19.03

For information on the equity compensation plans see Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters."

Item 6. Selected Financial Data.

Set forth below is our summary historical consolidated financial data. The consolidated statements of operations data for the years ended December 31, 2015, 2014 and 2013 and the consolidated balance sheet data as of December 31, 2015 and 2014 are derived from our audited consolidated financial statements included in this Form 10-K. The consolidated statements of operations data for the years ended December 31, 2012 and 2011 and the consolidated balance sheet data as of December 31, 2013, 2012 and 2011 are derived from our audited consolidated financial statements not included in this Form 10-K. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" presented elsewhere in this Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

	Year Ended December 31, 2015	2014	2013	2012	2011
	(in thousands, except per share data)				
Statement of operations data:					
Total revenue	$329,831	$265,493	$201,573	$114,528	$135,859
Operating income	34,440	54,981	47,728	19,022	55,424
Net (loss) income	(55,607)	(39,999)	10,072	(13,376)	25,906
Net loss attributable to noncontrolling interest	(23,074)	(8,709)	(6,887)	(7,089)	16,981
Net (loss) income attributable to Pattern Energy	$(32,533)	$(31,290)	$16,959	$(6,287)	$8,925
Less: Net income attributable to Pattern Energy prior to the initial public offering on October 2, 2013			(30,295)		
Net loss attributable to Pattern Energy subsequent to the initial public offering			$(13,336)		
Loss per share data:					
Class A common stock: basic and diluted loss per share	(0.46)	(0.56)	(0.17)	N/A	N/A
Class B common stock: basic and diluted loss per share	—	(0.49)	(0.48)	N/A	N/A
Dividends:					
Dividends declared per Class A common share	1.43	1.30	0.31	N/A	N/A
Deemed dividends per Class B common share	—	1.41	—	N/A	N/A
Balance sheet data:					
Total assets (1) (2)	3,829,592	2,795,287	1,872,233	1,999,347	1,362,272
Revolving credit facility	355,000	50,000	—	—	—
Convertible senior notes, net of financing costs	197,362	—	—	—	—
Long-term debt including current portion, net of financing costs(2)	1,218,524	1,413,858	1,217,820	1,254,187	839,394
Total liabilities	2,053,830	1,630,553	1,304,229	1,409,935	915,574

(1) Total revenues and total assets increased during the years ended and as of December 31, 2015 and 2014 compared to the years ended and as of December 31, 2014 and 2013, respectively, primarily due to acquisitions and the commencement of operations at various project wind farms. For further details of acquisitions, see Note 3, Acquisitions, in the notes to consolidated financial statements.

(2) In 2015, we early adopted ASU 2015-03, “Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs." As a result, we reclassified deferred financing costs from other assets to long-term debt. In the table above, prior year presentation of long-term debt reflects the reclassification of deferred financing costs.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and related notes included elsewhere in this Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. Our actual results may differ materially from those currently anticipated and expressed in such forward-looking statements as a result of a number of factors, including those we discuss under Item 1A "Risk Factors" elsewhere in this Form 10-K. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. See "Cautionary Notice Regarding Forward-Looking Statements."

Overview

We are an independent power company focused on owning and operating power projects with stable long-term cash flows in attractive markets with potential for continued growth of our business. We hold interests in 16 wind power projects located in the United States, Canada and Chile that use proven, best-in-class technology and have a total owned capacity of 2,282 MW. Each of our projects has contracted to sell all or a majority of its output pursuant to a long-term, fixed-price power sale agreement. Eighty-nine percent of the electricity to be generated by our projects will be sold under our power sale agreements which have a weighted average remaining contract life of approximately 14 years.

We intend to maximize long-term value for our stockholders in an environmentally responsible manner and with respect for the communities in which we operate. Our business is built around three core values of creative energy and spirit, pride of ownership and follow-through, and a team first attitude, which guide us in creating a safe, high-integrity work environment, applying rigorous analysis to all aspects of our business, and proactively working with our stakeholders to address environmental and community concerns. Our financial objectives, which we believe will maximize long-term value for our stockholders, are to produce stable and sustainable cash available for distribution, selectively grow our project portfolio and our dividend per Class A share and maintain a strong balance sheet and flexible capital structure.

Our growth strategy is focused on the acquisition of operational and construction-ready power projects from Pattern Development and other third parties that we believe will contribute to the growth of our business and enable us to increase our dividend per Class A share over time. Pattern Development is a leading developer of renewable energy and transmission projects. We believe Pattern Development's ownership position in our company incentivizes Pattern Development to support the successful execution of our objectives and business strategy, including through the development of projects to the stage where they are at least construction-ready. Currently, Pattern Development has a 5,900 MW pipeline of development projects, all of which are subject to our right of first offer. We target achieving a total owned capacity of 5,000 MW by year end 2019 through a combination of acquisitions from Pattern Development and other third parties capitalizing on the large fragmented global renewable energy market. In addition, we expect opportunities in Japan and Mexico will form part of our growth strategy.

The discussion and analysis below has been organized as follows:

- Factors that Significantly Affect our Business
  - Trends Affecting our Industry
  - Factors Affecting our Operational Results
- Key Metrics
- Results of Operations
- Liquidity and Capital Resources
  - Sources of Liquidity
  - Uses of Liquidity
  - Description of Credit Agreements
  - Tax Equity Partnership Agreements
- Critical Accounting Policies and Estimates

Factors that Significantly Affect our Business

Our results of operations in the near-term, as well as our ability to grow our business and revenue from electricity sales over time, could be impacted by a number of factors, including trends affecting our industry and factors affecting our operating results as discussed below:

Trends Affecting our Industry

Wind and solar power have been among the fastest growing sources of electricity generation in North America and globally over the past decade. This rapid growth is largely attributable to wind and solar power's increasing cost competitiveness with other electricity generation sources, the advantages of wind and solar power over other renewable energy sources and growing public support for renewable energy driven by concerns about security of energy supply and the environment. We expect these trends to continue to drive future growth in the wind power industry.

We believe that the key drivers for the long-term growth of renewable power include:

- increased demand for renewable energy resulting from regulatory or policy initiatives. Notable initiatives include country, state or provincial RPS programs, and, in the U.S., the EPA's 111d carbon regulations;
- governmental incentives for renewable energy including feed-in-tariff regimes, carbon credits and the U.S. federal based production or investment tax credits, which were extended through December 2019 (wind) and December 2022 (solar), that improve the cost competitiveness of renewable energy compared to traditional sources;

- new demand created by corporate and industrial buyers directly procuring renewable electricity on a large scale;
- efficiency and capital cost improvements in wind, solar and other renewable energy technologies, enabling wind and other forms of renewable energy to compete successfully in more markets;
- environmental and social factors supporting increasing levels of wind, solar and other renewable technologies in the generation mix;
- regulatory barriers increase the time, cost and difficulty of permitting new fossil fuel-fired facilities, notably coal, and nuclear facilities;
- decommissioning of aging coal-fired and nuclear facilities is expected to leave a gap in electricity supply; and
- policy initiatives to include such externalities as the cost of carbon pollution, methane leakage and water usage in conventional fossil fuel-fired electricity generation will increase costs of conventional generation.

In general, we continue to believe that there will be additional acquisition opportunities in the United States in the short term and that the longer-term growth trend will continue.

Our Outlook

Our projects are generally unaffected by short-term trends given that 89% of the electricity to be generated by our projects is to be sold under our fixed-price power sale agreements, which have a weighted average remaining life of approximately 14 years.

Our near-term growth strategy will focus on wind power projects, but will also include evaluation of solar power opportunities, and is largely insulated from the short-term trends. In September 2014, we announced the addition of our first solar project, the 104 MW Conejo Solar photovoltaic power project in Chile to our list of Identified ROFO projects, and in June of 2015 we added two Japanese solar projects to that list. We expect that most of our short-term growth will come from opportunities to acquire the Identified ROFO Projects, but we will evaluate unaffiliated third-party asset acquisition opportunities, as well.

Factors Affecting our Operational Results

The primary factors that will affect our financial results are (i) acquisitions and construction projects, (ii) integration with Pattern Development, (iii) electricity sales and energy derivative settlements of our operating projects, (iv) impact of derivative instruments, (v) project operations, and (vi) debt financing.

Acquisitions and Construction Projects

We construct our projects under fixed-price and fixed-schedule contracts with major equipment suppliers and experienced balance-of-plant construction companies. During 2015, we acquired Post Rock and Lost Creek, increased our interest in Gulf Wind, and, completed construction of Logan's Gap and Amazon Wind Farm Fowler Ridge, which increased operating capacity by 720 MW. During 2014, five of our construction projects achieved commercial operation and contributed 602 MW of additional operating capacity. In addition, in 2015, we acquired a one-third equity interest in K2 which increased our proportional capacity by 90 MW for a total proportional operating capacity of 292 MW for equity method investments. The acquisition of these projects significantly impacted our operating results and earnings from equity method investments. Our aggregate owned capacity is 2,282 MW.

We expect that the acquisition of operational and construction-ready power projects from Pattern Development and other third parties will contribute to our operational results. Below is a summary of the Identified ROFO Projects that we expect to acquire from Pattern Development in connection with our Project Purchase Right:

Identified ROFO Projects	Status	Location	Construction Start(1)	Commercial Operations(2)	Contract Type	Capacity (MW) Rated(3)	Pattern Development-Owned(4)
Armow	Operational	Ontario	2014	2015	PPA	180	90
Meikle	In construction	British Columbia	2015	2016	PPA	180	180
Conejo Solar	In construction	Chile	2015	2016	PPA	104	84
Belle River	Securing final permits	Ontario	2016	2017	PPA	100	50
Henvey Inlet	Late stage development	Ontario	2016	2017	PPA	300	150
Mont Sainte-Marguerite	Late stage development	Québec	2016	2017	PPA	147	147
North Kent	Late stage development	Ontario	2016	2017	PPA	100	43
Broadview projects	Late stage development	New Mexico	2016	2017	PPA	324	259
Grady	Late stage development	New Mexico	2016	2017	PPA	220	176
Tsugaru	Late stage development	Japan	2015	2018	PPA	126	63
Ohorayama	Late stage development	Japan	2015	2017	PPA	33	31
Kanagi Solar	In construction	Japan	2014	2016	PPA	14	6
Futtsu Solar	Operational	Japan	2014	2016	PPA	42	19
						1,870	1,298

(1) Represents date of actual or anticipated commencement of construction.
(2) Represents date of actual or anticipated commencement of commercial operations.
(3) Rated capacity represents the maximum electricity generating capacity of a project in MW. As a result of wind and other conditions, a project or a turbine will not operate at its rated capacity at all times and the amount of electricity generated may be less than its rated capacity.
(4) Pattern Development-owned capacity represents the maximum, or rated, electricity generating capacity of the project in MW multiplied by Pattern Development's percentage ownership interest in the distributable cash flow of the project.

Integration with Pattern Development

Our future net operating results should not be materially affected by the employee transfer, should it occur, as the consequential increase in general and administrative expense should be substantially or entirely offset by a reduction in related party general and administrative expense and an increase in related party other income. If the employee transfer should occur, there can be no assurance that Pattern Development's business activity will remain constant, decrease or increase. Separately, we and the equity owners of Pattern Development have begun discussions regarding a potential investment by us in a portion of the business of Pattern Development. There can be no assurance that any such transaction would in fact occur and at this time, the timing, structure, value and funding of any such transaction, should it occur, is uncertain.

Electricity Sales and Energy Derivative Settlements of our Operating Projects

Our electricity sales and energy derivative settlements are primarily determined by the price of electricity and any environmental attributes we sell under our power sale agreements and the amount of electricity that we produce, which is in turn principally the result of the wind conditions at our project sites and the performance of our equipment. We base our estimates of each project's capacity to generate electricity on the findings of our internal and external experts' long-term meteorological studies, which include on-site data collected from equipment on the property and relevant reference wind data from other sources, as well as specific equipment power curves and estimates for the performance of our equipment over time. Eighty-nine percent of the electricity to be generated across our projects is currently committed under long-term, fixed-price power sale agreements which have a weighted average remaining contract life of approximately 14 years.

Our wind analysis evaluates the wind's speed and prevailing direction, atmospheric conditions, and wake and seasonal variations for each project. The result of our meteorological analysis is a probabilistic assessment of a project's likely output. A P50 level of production indicates we believe a 50% probability exists that the electricity generated from a project will exceed a specified aggregate amount of electricity generation during a given period. While we plan for variability around this P50 production level, it generally provides the foundation for our base case expectation. The variability is measured in a spectrum of possible output levels such as a P75 output level, which indicates that over a specified period of time, such as one or ten years, the P75 output level would be exceeded 75% of the time. Similarly, the P25 output level would be exceeded 25% of the time. We often use P95, P90 and P75 production levels to plan ahead for low-wind years, while recognizing that we should also have corresponding high-wind years.

In addition to annual P50 variability, we also expect seasonal variability to occur. Variability increases as the period of review shortens, so it is likely that we will experience more variability in monthly or quarterly production than we do for annual production. Therefore, our periodic cash flow and payout ratios will also reflect more variability during periods shorter than a year. As a result, we use cash reserves to help manage short term production and cash flow variability.

When analyzed together, a portfolio's probability of exceeding a specific output level changes when all the projects are considered as a portfolio instead of on a stand-alone basis. Due to the geographical separation between our projects, the uncertainty variables and wind speed correlations are diverse enough across the portfolio to provide improvement in the overall uncertainty, which we refer to as the portfolio effect. For example, the sum of our individual projects' P75 output levels is approximately 93% of the aggregate P50 output level (which is unaffected by the portfolio effect), while the P75 output level, when taking into account the portfolio effect, is approximately 96% of our aggregate P50 output level. On a portfolio basis, our P90 and P95 production estimates for the annual electricity generation of our sixteen projects are approximately 92% and 89%, respectively, of our estimated P50 output levels. The portfolio effect results in an improvement in the production stability across the portfolio. A greater diversity of projects in the portfolio has the effect of increasing the frequency of occurrences aggregated around the expected result (probability level).

Our electricity generation is also dependent on the equipment that we use. We have selected high-quality equipment with a goal of having a concentration of turbines from top manufacturers. With a combination of high-quality equipment and scale and in-house operating capability, we have structured our projects such that we may expect high availability and long-term production from the equipment, develop operating expertise and experience, which can be shared among our operators, obtain a high level of attention and focus from the manufacturers and common operating practices. Given our manufacturers' global fleet sizes and strong balance sheets, the warranties that we secure for our turbines and our operating approach described below, we are confident in our expectations for reliable long-term turbine operation.

Impact of Derivative Instruments

Where possible, we have sought to protect ourselves against electricity and interest rate exposures with a relatively longer term hedging strategy. We expect to hedge exposure to foreign currency exchange rates in the future over shorter periods of time. Accordingly, we have experienced in the past, and expect to record in the future, substantial volatility in the components of our net income that relate to the mark-to-market adjustments on our undesignated energy and interest rate derivatives.

We believe that mark-to-market adjustments that we make to the fair value of our derivative assets and liabilities are generally mirrored by changes in the economic value of the related operating or financial assets, such as our wind projects and our project loans, for which the application of accounting principles generally accepted in the United States ("U.S. GAAP") does not permit us to record such economic gains and losses. For this reason, and because one of our principal financial objectives is to produce stable and sustainable cash available for distribution, we believe that the economic value to our shareholders reflected in these derivative instruments, outweighs the risk of volatility in net income that we expect to report. Accordingly, we believe it is useful to investors to consider supplemental financial measures that we report, such as adjusted EBITDA, where we have subtracted and added back, as applicable, the unrealized gains and losses arising from mark-to-market adjustments on our derivative instruments, and cash available for distribution.

Project Operations

Our ability to generate electricity in an efficient and cost-effective manner is impacted by our ability to maintain the operating capacity of our projects. We use reliable and proven wind turbines and other equipment for each of our projects.

For the years ended December 31, 2015 and 2014, our turbine availability across our projects was 97.3% and 95.7%, respectively. For the years ended December 31, 2015 and 2014, Gulf Wind had higher than normal downtime due primarily to blade and other warranty issues which were compensated by the manufacturer. The fleet excluding Gulf Wind but including several new sites that achieved commercial operation in 2015 and 2014, had an average turbine availability of 98.2% and 97.2%, respectively, which is in line with industry standards for original investment projections reviewed by independent engineering firms.

See Item 1 "Business—Organization of Our Business—Operations and Maintenance." To accomplish this level of availability, we provide forward-looking wind forecasts to each of our sites twice a day. Our site managers use this information to plan the maintenance activities for those days, in order to schedule maintenance during low wind periods, where impact to revenues is minimized. In addition, for sites with power prices that vary during different periods, we schedule work to avoid known or anticipated high price periods.

Debt Financing

We intend to use a portion of our revenue from electricity sales to cover our subsidiaries' interest expense and principal payments on borrowings under their respective project financing facilities. Our interest expense primarily reflects (i) imputed interest on the lease financing of our Hatchet Ridge project, (ii) periodic interest on the term loan financing arrangements, including the effects of interest rate swaps, at our other operating projects, (iii) interest on our convertible senior notes and (iv) interest on short-term loan facilities, including any borrowings under our revolving credit facility.

We believe that our projects have been financed on average with stronger coverage ratios than is typical in our industry. A debt service coverage ratio is generally defined as a project's operating cash flows divided by scheduled payments of principal and interest for a period. While we believe that the commercial bank market generally seeks a minimum average annual debt service coverage ratio for wind power projects, based on P50 output levels, of between 1.4 and 1.5 to 1.0, our projects, on a portfolio basis, have an expected average annual debt service coverage ratio over the remaining scheduled loan amortization periods of approximately 1.7 to 1.0.

Key Metrics

We regularly review a number of financial measurements and operating metrics to evaluate our performance, measure our growth and make strategic decisions. In addition to traditional U.S. GAAP performance and liquidity measures, such as total revenue, cost of revenue, net (loss) income and net cash provided by operating activities, we also consider cash available for distribution as a supplemental liquidity measure and adjusted EBITDA, MWh sold and average realized electricity price in evaluating our operating performance. We disclose adjusted EBITDA, which is a non-U.S. GAAP measure, because management believes this metric assists investors and analysts in comparing our operating performance across reporting periods on a consistent basis by excluding items that our management believes are not indicative of our core operating performance. We disclose cash available for distribution because management recognizes that it will be used as a supplemental measure by investors and analysts to evaluate our liquidity. Each of these key metrics is discussed below.

Cash Available for Distribution

We define cash available for distribution as net cash provided by operating activities as adjusted for certain other cash flow items that we associate with our operations. It is a non-U.S. GAAP measure of our ability to generate cash to service our dividends.

Cash available for distribution represents cash provided by operating activities as adjusted to (i) add or subtract changes in operating assets and liabilities, (ii) subtract net deposits into restricted cash accounts, which are required pursuant to the cash reserve requirements of financing agreements, to the extent they are paid from operating cash flows during a period, (iii) subtract cash distributions paid to noncontrolling interests, (iv) subtract scheduled project-level debt repayments in accordance with the related loan amortization schedule, to the extent they are paid from operating cash flows during a period, (v) subtract non-expansionary capital expenditures, to the extent they are paid from operating cash flows during a period, (vi) add cash distributions received from unconsolidated investments, to the extent such distributions were derived from operating cash flows and (vii) add or subtract other items as necessary to present the cash flows we deem representative of our core business operations.

The most directly comparable U.S. GAAP measure to cash available for distribution is net cash provided by operating activities. The following table is a reconciliation of our net cash provided by operating activities to cash available for distribution for the periods presented (unaudited and in thousands):

	Year ended December 31,		
	2015	2014	2013
Net cash provided by operating activities	$117,849	$110,448	$78,152
Changes in operating assets and liabilities	(6,880)	(9,002)	8,237
Network upgrade reimbursement	2,472	2,472	1,854
Release of restricted cash to fund project and general and administrative costs	1,611	223	318
Operations and maintenance capital expenditures	(779)	(267)	(819)
Transaction costs for acquisitions	1,598	1,730	—
Distributions from unconsolidated investments	34,216	7,891	—
Reduction of other asset - Gulf Wind energy derivative deposit	6,205	—	—
Other	(1,921)	—	—
Less:			
Distributions to noncontrolling interests	(7,882)	(2,100)	(2,292)
Principal payments paid from operating cash flows	(54,041)	$(49,246)	$(42,829)
Cash available for distribution	$92,448	$62,149	$42,621

Cash available for distribution was $92.4 million for the year ended December 31, 2015 as compared to $62.1 million for the same period in the prior year. This $30.3 million increase in cash available for distribution was due to additional revenues of $63.1 million (excluding unrealized loss on energy derivative and amortization of PPAs) primarily from projects which commenced commercial operations or were acquired during 2014 and 2015. In addition, we received an increase of $26.3 million in cash distributions from our unconsolidated investments when compared to the same period in the prior year which was due to full year operation at each of South Kent and Grand in 2015 compared to partial year operation in 2014 and the acquisition of K2 in the second quarter of 2015. Cash available for distribution was also impacted by a $6.2 million cash distribution from the partial refund of a deposit associated with the Gulf Wind energy derivative. These increases were partially offset by increases in project expenses of $36.8 million, operating expenses of $9.1 million, interest expense of $10.2 million, primarily from projects which commenced commercial operations during 2014 and 2015. In addition, increases in cash available for distribution were offset by increased distributions to noncontrolling interests of $5.8 million and increased principal payments of $4.8 million.

Cash available for distribution was $62.1 million for the year ended December 31, 2014 as compared to $42.6 million for the same period in the prior year. This $19.5 million increase in cash available for distribution was primarily the result of additional revenues of $56.5 million (excluding unrealized loss on energy derivative) from projects which commenced commercial operations during 2013 and 2014. In addition, we recorded a $7.9 million cash distribution from unconsolidated investments. Partially offsetting these increases in electricity sales were increases of $20.1 million in project expenses, $11.7 million in operating expenses, excluding a noncash employee stock-based compensation expense increase of $3.6 million, $6.4 million in principal payments from operating cash and $6.1 million in interest expense and related derivative settlements.

Adjusted EBITDA

We define adjusted EBITDA as net (loss) income before net interest expense, income taxes and depreciation, amortization and accretion, including our proportionate share of net interest expense, income taxes and depreciation, amortization and accretion of joint venture investments that are accounted for under the equity method. Adjusted EBITDA is a non-U.S. GAAP measure. Adjusted EBITDA also excludes the effect of certain mark-to-market adjustments and infrequent items not related to normal or ongoing operations, such as early payment of debt and realized derivative gain or loss from refinancing transactions, and gain or loss related to acquisitions or divestitures. In calculating adjusted EBITDA, we exclude mark-to-market adjustments to the value of our derivatives because we believe that it is useful for investors to understand, as a supplement to net (loss) income and other traditional measures of operating results, the results of our operations without regard to periodic, and sometimes material, fluctuations in the market value of such assets or liabilities.

The most directly comparable U.S. GAAP measure to adjusted EBITDA is net (loss) income. The following table reconciles net (loss) income to adjusted EBITDA for the periods presented (unaudited and in thousands):

	Year ended December 31,		
	2015	2014	2013
Net (loss) income	$(55,607)	$(39,999)	$10,072
Plus:			
Interest expense, net of interest income	75,309	66,729	61,118
Tax provision	4,943	3,136	4,546
Depreciation, amortization and accretion	143,376	104,417	83,180
Amortization of purchase power agreements, net (1)	1,946	—	—
EBITDA	$169,967	$134,283	$158,916
Unrealized loss on energy derivative (1)	791	3,878	11,272
Loss (gain) on undesignated derivatives, net	5,490	15,743	(13,502)
Realized loss on designated derivatives	11,221	—	—
Early extinguishment of debt	4,941	—	—
Net loss (gain) on transactions	3,400	(13,843)	(5,995)
Plus, proportionate share from equity accounted investments:			
Interest expense, net of interest income	23,537	14,081	267
Tax provision (benefit)	—	102	(172)
Depreciation, amortization and accretion	22,680	13,720	20
Loss (gain) on undesignated derivatives, net	8,514	30,148	(9,037)
Adjusted EBITDA	$250,541	$198,112	$141,769

(1) Amount is included in electricity sales on the consolidated statements of operations.

Adjusted EBITDA for the year ended December 31, 2015 was $250.5 million compared to $198.1 million for the same period in the prior year, an increase of $52.4 million, or approximately 26.5%. The increase in adjusted EBITDA during 2015 as compared to 2014 was primarily attributable to projects which commenced commercial operations or were acquired in 2014 and 2015.

Adjusted EBITDA for the year ended December 31, 2014 was $198.1 million compared to $141.8 million for the same period in the prior year, an increase of $56.3 million, or approximately 39.7%. The increase in adjusted EBITDA during 2014 as compared to 2013 was primarily attributable to projects which commenced commercial operations in 2013 and 2014.

MWh Sold and Average Realized Electricity Price

The number of consolidated MWh, equity method proportional MWh and proportional MWh sold, as well as consolidated average realized price per MWh and the proportional average realized price per MWh sold, are the operating metrics that help explain trends in our revenue, earnings from our equity method investments and net income attributable to us.

- Consolidated MWh sold for any period presented, represents 100% of MWh sold by wholly-owned and partially-owned subsidiaries in which we have a controlling interest and are consolidated in our consolidated financial statements;
- Noncontrolling interest MWh represents that portion of partially-owned subsidiaries not attributable to us;
- Controlling interest in consolidated MWh is the difference between the consolidated MWh sold and the noncontrolling interest MWh;
- Equity method investment proportional MWh is our proportion in MWh sold from our equity method investments;
- Proportional MWh sold for any period presented, represents the sum of the controlling interest and our percentage interest in our equity method investments; and
- Average realized electricity price for each of consolidated MWh sold, equity method investment proportional MWh sold and proportional MWh sold represents (i) total revenue from electricity sales for each of the respective MWh sold, discussed above, excluding unrealized gains and losses on our energy derivative and the amortization of

finite-lived intangible assets and liabilities, divided by (ii) the respective MWh sold.

The following table presents selected operating performance metrics for the periods presented (unaudited):

	Year ended December 31,			
MWh sold	2015	2014	Change	% Change
Consolidated MWh sold	5,257,976	3,241,277	2,016,699	62.2 %
Less: noncontrolling MWh	(877,847)	(586,020)	(291,827)	49.8 %
Controlling interest in consolidated MWh	4,380,129	2,655,257	1,724,872	65.0 %
Equity method investment proportional MWh	756,546	295,976	460,570	155.6 %
Proportional MWh sold	5,136,675	2,951,233	2,185,442	74.1 %
Average realized electricity price per MWh				
Consolidated average realized electricity price per MWh	$62	$80	$(18)	(22.5)%
Equity method investment proportional average realized electricity price per MWh	$118	$134	$(16)	(11.9)%
Proportional average realized electricity price per MWh	$73	$90	$(17)	(18.9)%

Our consolidated MWh sold for the year ended December 31, 2015 was 5,257,976 MWh, as compared to 3,241,277 MWh for the year ended December 31, 2014, an increase of 2,016,699 MWh, or 62.2%. The change in consolidated MWh sold was primarily attributable to:

- an increase in volume of 1,173,786 MWh from projects which commenced commercial operations during 2014;
- an increase in volume of 718,275 MWh from projects acquired in 2015; and
- an increase in volume of 271,695 MWh from projects which completed construction during 2015.

Offsetting the increases in consolidated MWh sold were decreases of 147,506 MWh in volume from projects in operation prior to 2014.

Our proportional MWh sold for the year ended December 31, 2015 was 5,136,675 MWh, as compared to 2,951,233 MWh for the year ended December 31, 2014, an increase of 2,185,442 MWh, or 74.1%. The change in proportional MWh sold was primarily attributable to:

- an increase in volume of 1,724,872 MWh from controlling interest in consolidated MWh; and
- an increase in volume of 460,570 MWh from equity method investments due to the acquisition of K2 in 2015 and commencement of operations of South Kent and Grand in 2014.

Our consolidated average realized electricity price was $62 per MWh for the year ended December 31, 2015 as compared to $80 per MWh for the year ended December 31, 2014. The decrease of $18 per MWh was primarily due to new projects which were acquired or commenced commercial operation in 2014 and 2015 at PPA pricing approximately 50% lower, on average, than projects in operation prior to 2014.

Proportional average realized electricity price was $73 per MWh for the year ended December 31, 2015 as compared to $90 per MWh for the year ended December 31, 2014. The $17 per MWh decrease in the proportional average realized electricity price was primarily due to the impact of foreign exchange on revenue denominated in the Canadian dollar at our Canadian projects and, similar to consolidated average realized electricity prices, new projects which were acquired or commenced commercial operation in 2014 and 2015 at PPA pricing approximately 50% lower, on average, than projects in operation prior to 2014.

The following table presents selected operating performance metrics for the periods presented (unaudited):

	Year ended December 31,			
MWh sold	2014	2013	Change	% Change
Consolidated MWh sold	3,241,277	2,258,811	982,466	43.5 %
Less: noncontrolling MWh	(586,020)	(487,039)	(98,981)	20.3 %
Controlling interest in consolidated MWh	2,655,257	1,771,772	883,485	49.9 %
Equity method investment proportional MWh	295,976	—	295,976	100.0 %
Proportional MWh sold	2,951,233	1,771,772	1,179,461	66.6 %
Average realized electricity price per MWh				
Consolidated average realized electricity price per MWh	$80	$84	$(4)	(4.8)%
Equity method investment proportional average realized electricity price per MWh	$134	$—	$134	100.0 %
Proportional average realized electricity price per MWh	$90	$92	$(2)	(2.2)%

Our consolidated MWh sold for the year ended December 31, 2014 was 3,241,277 MWh, as compared to 2,258,811 MWh for the year ended December 31, 2014, an increase of 982,466 MWh, or 43.5%. The change in consolidated MWh sold was primarily attributable to:

- an increase in volume of 645,607 MWh from projects which commenced commercial operations during 2014;
- an increase in volume of 236,027 MWh from projects which commenced commercial operations in 2013; and
- an increase in volume of 100,834 MWh from projects in operation prior to 2013.

Our proportional MWh sold in the year ended December 31, 2014 was 2,951,233 MWh, as compared to 1,771,772 MWh for the year ended December 31, 2013, representing an increase of 1,179,461 MWh or approximately 66.6%. This change in proportional MWh sold during 2014 as compared to 2013 was primarily attributable to

- an increase in volume of 883,485 MWh from controlling interest in consolidated MWh; and
- an increase in volume of 295,976 MWh from equity method investments due to commencement of operations of South Kent and Grand in 2014.

Our consolidated average realized electricity price was $80 per MWh for the year ended December 31, 2014 as compared to $84 per MWh for the year ended December 31, 2013. The decrease in the consolidated average realized electricity price was primarily due to new projects that commenced commercial operation in 2014 at PPA pricing approximately 50% lower, on average, than projects in operation prior to 2014.

Our proportional average realized electricity price for the year ended December 31, 2014 was comparable to the proportional average realized electricity price for the year ended December 31, 2013.

Results of Operations

The following table provides selected financial information for the periods presented (in thousands, except percentages):

	Year ended December 31,			2015 vs. 2014		2014 vs. 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Total revenue	$329,831	$265,493	$201,573	$64,338	24.2 %	$63,920	31.7 %
Total cost of revenue	257,995	182,192	140,857	75,803	41.6	41,335	29.3
Total operating expenses	37,396	28,320	12,988	9,076	32.0	15,332	118.0
Total other expense	85,104	91,844	33,110	(6,740)	(7.3)	58,734	177.4
Net (loss) income before income tax	(50,664)	(36,863)	14,618	(13,801)	37.4	(51,481)	(352.2)
Tax provision	4,943	3,136	4,546	1,807	57.6	(1,410)	(31.0)
Net (loss) income	(55,607)	(39,999)	10,072	(15,608)	39.0	(50,071)	(497.1)
Net loss attributable to noncontrolling interest	(23,074)	(8,709)	(6,887)	(14,365)	164.9	(1,822)	26.5
Net (loss) income attributable to Pattern Energy	$(32,533)	$(31,290)	$16,959	$(1,243)	4.0 %	$(48,249)	(284.5)%

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and
Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Total Revenue

Total revenue for the year ended December 31, 2015 was $329.8 million compared to $265.5 million for the year ended December 31, 2014, an increase of $64.3 million, or approximately 24.2%. The increase in total revenue for the year ended December 31, 2015 as compared to the prior year was primarily attributable to:

- $42.3 million in additional electricity sales from projects which commenced commercial operations during 2014;
- $33.0 million from projects acquired in 2015;
- $6.3 million from projects which completed construction during 2015; and
- $3.1 million in lower unrealized losses due to lower forward electricity price curves when compared to the prior year.

The increases in total revenues were partially offset by:

- $13.2 million in lower electricity sales from projects in operation prior to 2014; and
- $5.6 million decrease in other revenues associated with performance of our turbines in accordance with contracted terms with our turbine manufacturers.

Total revenue for the year ended December 31, 2014 was $265.5 million compared to $201.6 million for the year ended December 31, 2013, an increase of $63.9 million, or approximately 31.7%. The change in total revenue for the year ended December 31, 2014 as compared to the prior year was primarily attributable to:

- $30.8 million from projects which commenced commercial operations during 2014;
- $24.8 million in additional electricity sales from projects which commenced commercial operations in 2013;
- $15.4 million increase in volume from projects in operation prior to 2013; and
- $7.4 million in lower unrealized losses due to lower forward gas price curves when compared to the prior year.

The increases in total revenue were partially offset by decreases of $14.4 million in other revenues associated with performance of our turbines in accordance with contracted terms with our turbine manufacturers.

Cost of revenue

Cost of revenue for the year ended December 31, 2015 was $258.0 million compared to $182.2 million for the year ended December 31, 2014, an increase of $75.8 million, or approximately 41.6%. The increase in cost of revenue during 2015 as compared to 2014 was primarily attributable to:

- an $17.3 million increase in expenses associated with turbine operations and maintenance for new projects which were acquired or became commercially operable during 2014 and 2015 as discussed above;

- an $8.1 million increase in property taxes, a $3.1 million increase in land lease and royalties, and a $5.0 million increase in other expenses associated with new projects;
- a $20.4 million increase in depreciation for projects which became commercially operable during 2014; and
- a $25.4 million increase in depreciation for projects which were acquired or became commercially operable during 2015.

The increases in cost of revenue were partially offset by a $4.8 million decrease in depreciation due to the change in depreciable life from 20 to 25 years effective January 1, 2015. See Note 2, Summary of Significant Accounting Policies in the notes to consolidated financial statements.

Cost of revenue for the year ended December 31, 2014 was $182.2 million compared to $140.9 million for the year ended December 31, 2013, an increase of $41.3 million, or approximately 29.3%. The increase in cost of revenue during 2014 as compared to 2013 was primarily attributable to:

- a $10.0 million increase in project expenses associated with turbine operations and maintenance for new projects which became commercially operable during 2013 and 2014;
- a $7.7 million increase in other expenses primarily associated with new projects; and
- a $21.6 million increase in depreciation for projects which became commercially operable during 2013 and 2014.

As each new project commences commercial operations, we incur new incremental and ongoing costs for maintenance and services agreements, property taxes, insurance, land lease, depreciation and other costs associated with managing, operating and maintaining the facility, including adding site employees and other operations staff.

Operating expenses

Operating expenses for the year ended December 31, 2015 were $37.4 million compared to $28.3 million for the year ended December 31, 2014, an increase of $9.1 million, or approximately 32.0%. The increase in operating expenses during 2015 as compared to 2014 was primarily attributable to:

- a $4.3 million increase in payroll and non-cash stock based compensation to support new projects which were acquired or became commercially operable during 2014 and 2015 as discussed above; and
- a $3.4 million increase in professional fees associated with being a public company.

Operating expenses for the year ended December 31, 2014 were $28.3 million compared to $13.0 million for the year ended December 31, 2013, an increase of $15.3 million, or approximately 118.0%. The increase in operating expenses during 2014 as compared to 2013 was primarily attributable to:

- a $12.4 million increase in payroll and non-cash stock based compensation expenses to support new and existing projects; and
- an $1.5 million increase in professional fees associated with being a public company.

Other expense

Other expense for the year ended December 31, 2015 was $85.1 million compared to $91.8 million for the year ended December 31, 2014, a decrease of $6.7 million, or approximately 7.3%. The change was primarily attributable to:

- a $41.4 million increase in equity in earnings in unconsolidated investments due primarily to gains of $21.6 million in interest rate derivatives compared to losses in the prior year, and a $22.1 million increase in project income; and
- a $10.3 million increase in (loss) gain on undesignated derivatives, net primarily due to decreased losses of $10.7 million from interest rate price curves compared to the interest rate price curves in the prior year; $5.1 million gains from foreign currency derivative settlements as foreign currency transaction rates were greater than contract rates, partially offset by reclassification from accumulated other comprehensive income of $5.5 million as a result of the de-designation of an interest rate swap at Spring Valley.

These increases were partially offset by the following:

- a $17.2 million decrease in net gain (loss) on transactions primarily due to $17.9 million gain recognized in 2014 for the purchase of El Arrayán project;

- an $11.2 million decrease in realized gain (loss) on designated derivatives, net due to the termination of interest rate swap and cap associated with the repayment of debt at Gulf Wind;
- a $10.2 million increase in interest expense primarily due to the issuance of convertible debt in July 2015, increased loan balances on the revolving credit facility and increased project-level debt due to acquisitions; and
- a $4.9 million loss primarily from loss on early extinguishment of debt at Gulf Wind of $4.1 million.

Other expense for the year ended December 31, 2014 was $91.8 million compared to $33.1 million for the year ended December 31, 2013, an increase of $58.7 million, or approximately 177.4%. The increase in other expense during 2014 as compared to 2013 was primarily attributable to:

- a $33.1 million increase in equity losses in unconsolidated investments which were primarily related to unrealized loss on interest rate derivatives;
- a $29.2 million increase in loss on undesignated derivatives, net; and
- a $4.1 million increase in interest expense.

Partially offsetting these increased losses was a $7.8 million increase in net gain on transactions, principally related to our acquisition of an additional 38.5% interest in El Arrayán.

Tax provision

The tax provision was $4.9 million for the year ended December 31, 2015 compared to $3.1 million for the year ended December 31, 2014. The expense of $4.9 million is principally related to our Canadian operations offset against tax benefits earned in our Chilean operations.

The tax provision was $3.1 million for the year ended December 31, 2014 compared to $4.5 million for the same period in the prior year. The expense of $3.1 million is primarily related to the fair value remeasurement of our original 31.5% interest in El Arrayán and the effect of a tax regime change in Chile, offset against tax benefits earned in our Canadian operations.

Noncontrolling interest

The net loss attributable to noncontrolling interest was $23.1 million for the year ended December 31, 2015 compared to a $8.7 million net loss attributable to noncontrolling interest for the year ended December 31, 2014. The increased loss of $14.4 million, or approximately 164.9%, was primarily attributable to allocations of losses for tax equity projects which commenced commercial operations or were acquired during 2014 and 2015.

The net loss attributable to noncontrolling interest was $8.7 million for the year ended December 31, 2014 compared to a $6.9 million net loss attributable to noncontrolling interest for the year ended December 31, 2013. The increased loss of $1.8 million, or approximately 26.5%, was primarily attributable to allocations of losses for tax equity projects which commenced commercial operations during 2014.

Liquidity and Capital Resources

Our business requires substantial capital to fund (i) equity investments in our construction projects, (ii) current operational costs, (iii) debt service payments, (iv) dividends to our stockholders, (v) potential investments in new acquisitions, (vi) modifications to our projects, (vii) unforeseen events and (viii) other business expenses. As a part of our liquidity strategy, we plan to retain a portion of our cash flows in above-average wind years in order to have additional liquidity in below-average wind years.

Sources of Liquidity

Our sources of liquidity include cash generated by our operations, cash reserves, borrowings under our corporate and project-level credit agreements and further issuances of equity and debt securities.

The principal indicators of our liquidity are our unrestricted and restricted cash balances and availability under our revolving credit facility and project level facilities. Our available liquidity is as follows (in millions):

	December 31, 2015
Unrestricted cash	$94.8
Restricted cash	51.5
Revolving credit facility	117.8
Project facilities:	
Post construction use	104.3
Total available liquidity	$368.4

We believe that throughout 2016, we will have sufficient liquid assets, cash flows from operations, and borrowings available under our revolving credit facility to meet our financial commitments, debt service obligations, contingencies and anticipated required capital expenditures for at least the next 24 months, not including capital required for additional project acquisitions. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce a corresponding adverse effect on our borrowing capacity. In connection with our future capital expenditures and other investments, including any project acquisitions that we may make, we may, from time to time, issue debt or equity securities. Our ability to access the debt and equity markets is dependent on, among other factors, the overall state of the debt and equity markets and investor appetite for investment in clean energy projects in general and our Class A shares in particular. Volatility in the market price of our Class A shares may prevent or limit our ability to utilize our equity securities as a source of capital to help fund acquisitions. An inability to obtain debt or equity financing on commercially reasonable terms could significantly limit our timing and ability to consummate future acquisitions, and to effectuate our growth strategy.

Financing Developments

Since May 2015, we have consummated repricings and refinancings of borrowings under several of our project level finance facilities, including at South Kent, Lost Creek, Spring Valley, St. Joseph and our Revolving Credit Facility. As a result of such repricings and refinancings, we have (among other things) reduced the interest rates charges paid under the project finance facilities, reduced the size of future scheduled step-ups in interest rates and extended the time periods prior to such scheduled step-ups becoming effective, and made prepayments of amounts due under the facilities and thereby reduced the aggregate principal amount subject to financing, while also negotiating elimination of certain reserve accounts under such facilities.

In addition, during the third quarter of 2015, we also prepaid 100% of the outstanding balance of the Gulf Wind project’s term loan of $154.1 million. Such repricings, refinancings, and repayments result in both current and long-term future financial benefits to us, including reduced interest expense, reduced project-level debt scheduled principal repayments, increased likelihood the projects will be able to satisfy conditions precedent to distribute excess cash flows upstream to owners, and reduced capital allocated to project-level standby reserves which have beneficial effects to our consolidated statements of operations, as well as net cash provided by operating activities which is the most directly comparable U.S. GAAP measure to our cash available for distribution.

We believe the effects of these repricings, refinancings, and repayments have helped, and will continue to help, contribute to offsetting effects of other events which have occurred in 2015 and may continue in 2016, such as low wind levels which have occurred across the western United States and Texas, which negatively impacts net cash provided by operating activities, as well as, indirectly, cash available for distribution. Subject to market conditions, we will continue to consider various forms of repricings, refinancings, and/or repayments of our project level finance facilities. No assurances, however, can be given that we will be able to consummate any such transactions, the transactions can be consummated on terms that are financially favorable to us, or that such transactions will have the intended financial effects of improving the consolidated statements of operations, net cash provided by operating activities, or cash available for distribution.

Cash Flows

We use traditional measures of cash flow, including net cash provided by operating activities, net cash used in investing activities and net cash provided by financing activities, as well as cash available for distribution discussed earlier, to evaluate our periodic cash flow results. Below is a summary of our cash flows for each period (in millions):

	Year ended December 31,		
	2015	2014	2013
Net cash provided by operating activities	$117.8	$110.4	$78.2
Net cash (used in) provided by investing activities	(765.2)	(379.4)	72.4
Net cash provided by financing activities	645.3	269.0	(63.4)
Effect of exchange rate changes on cash and cash equivalents	(4.8)	(2.0)	(1.1)
Net change in cash and cash equivalents	$(6.8)	$(1.9)	$86.0

Net cash provided by operating activities

Net cash provided by operating activities was $117.8 million for the year ended December 31, 2015 as compared to $110.4 million in the prior year, an increase of $7.4 million, or approximately 6.7%. The increase in cash provided by operating activities was primarily the result of higher revenue of approximately $63.1 million, excluding unrealized loss on energy derivative and amortization of PPAs. Offsetting these increases in revenue were increases of $36.8 million in project expenses, $9.1 million in operating expenses, and $10.2 million in interest expense.

Net cash provided by operating activities was $110.4 million for the year ended December 31, 2014 as compared to $78.2 million in the prior year, an increase of $32.3 million, or approximately 41.3%. The increase in cash provided by operating activities was the result of higher revenue of $56.5 million, excluding unrealized loss on energy derivative, which was primarily attributable to the commencement of commercial operations at both El Arrayán and Panhandle 1 in June 2014 and increased production at Ocotillo. In addition to the increase was a $16.9 million net change in operating assets and liabilities. Offsetting these increases in revenue were increases of $20.1 million in project expenses, $11.7 million in operating expenses, excluding a $3.6 million increase in noncash employee stock-based compensation expense, and $6.1 million in interest expense and related derivative settlements.

Net cash (used in) provided by investing activities

Net cash used in investing activities was $765.2 million for the year ended December 31, 2015, which consisted primarily of $433.8 million of acquisitions, net of cash acquired, which primarily includes $238.5 million for both Lost Creek and Post Rock, $65.2 million for Amazon Wind Farm Fowler Ridge and $128.4 million for an unconsolidated investment in K2, in addition to $380.5 million for capital expenditures primarily related to the construction at Logan's Gap and Amazon Wind Farm Fowler Ridge. These increases were partially offset by $38.2 million of distributions from unconsolidated investments.

Net cash used in investing activities was $379.4 million for the year ended December 31, 2014, which consisted primarily of $119.5 million for capital expenditures, $306.6 million of acquisitions, net of cash acquired, including $123.4 million for Panhandle 1, $123.6 million for Panhandle 2, $44.6 million for the additional 38.5% interest in El Arrayán and $15.1 million for Logan's Gap. This is partially offset by $22.0 million of distributions from unconsolidated investments and a $17.5 million increase in other assets driven by cash received from a refund of security deposit related to an energy hedge arrangement upon commercial operations of Panhandle 2.

Net cash provided by investing activities was $72.4 million for the year ended December 31, 2013, which consisted of $173.4 million of ITC grant proceeds at Ocotillo and Santa Isabel, $14.3 million of proceeds from the sale of investments and tax credits, and a net reduction in our reimbursable interconnection receivable of $49.7 million, offset by $123.5 million of capital expenditures primarily at Ocotillo and Santa Isabel and a funding of restricted cash primarily at Ocotillo under the credit agreement.

Net cash provided by financing activities

Net cash provided by financing activities for the year ended December 31, 2015 was $645.3 million, which consisted of proceeds of $317.4 million from the February and July 2015 equity offerings, $218.9 million from the July 2015 issuance of convertible debt, net of issuance costs, $405.0 million from the revolving credit facility, issuance of long-term debt at St. Joseph of $165.0 million, $329.1 million in construction loans, and tax equity funding for

Logan's Gap of $192.9 million and Amazon Wind Farm Fowler Ridge of $143.1 million. Offsetting these increases were dividend payments of $90.6 million, payments of $121.2 million for the purchase of the noncontrolling interests at Gulf Wind and Lost Creek in July 2015, and repayments of $785.9 million in long-term debt related to Gulf Wind, St. Joseph, Logan's Gap, and Amazon Wind Farm Fowler Ridge.

Net cash provided by financing activities for the year ended December 31, 2014 was $269.0 million, which consisted of $286.8 million of proceeds from our May 2014 equity offering, net of transaction costs, $200.8 million in capital contributions from noncontrolling investees of Panhandle 1 and Panhandle 2, $50.0 million drawn on a credit facility, partially offset by a $259.4 million repayment of long-term debt, of which $195.4 million relates to the repayment of the Panhandle 2 construction loan, and $52.3 million of dividend payments.

Net cash used in financing activities for the year ended December 31, 2013 was $63.4 million, which was attributable to $317.9 million of net initial public offering proceeds, $138.6 million of loan proceeds primarily at Santa Isabel and Ocotillo and $32.7 million of capital contributions prior to the initial public offering offset by $232.6 million of distributions to Pattern Development in conjunction with the Contribution Transactions, $49.4 million related to the acquisition of Grand from Pattern Development, repayment of $114.1 million of construction and bridge loans at Santa Isabel and Ocotillo, $98.9 million of capital distributions prior to our initial public offering, and $50.3 million of long-term debt repayments.

Uses of Liquidity

Cash Dividends to Investors

We intend to pay regular quarterly dividends in U.S. dollars to holders of our Class A common stock. On February 24, 2016, we increased our dividend to $0.3810 per Class A share, or $1.524 per Class A share on an annualized basis, commencing with respect to dividends to be paid on April 29, 2016 to holders of record on March 31, 2016.

We established our initial quarterly dividend level based on a targeted cash available for distribution payout ratio of 80%, after considering the annual cash available for distribution that we expect our projects will be able to generate following the commencement of commercial operations at all of our construction projects and with due regard to retaining a portion of the cash available for distribution to grow our business. We intend to grow our business primarily through the acquisition of operational and construction-ready power projects, which, we believe, will facilitate the growth of our cash available for distribution and enable us to increase our dividend per share of Class A common stock over time. We may in the future raise capital and make investments in new power projects upon or near the commencement of construction of such projects and therefore prior to the expected commencement of operations of the new projects, which could result in a passage of time of twelve or more months before we begin to receive any cash flow contributions from such projects to our cash available for distribution. In connection with these investments, we may increase our dividends prior to the receipt of such cash flow contributions, which would likely cause our payout ratio to temporarily exceed our targeted run-rate payout ratio. However, the determination of the amount of cash dividends to be paid to holders of our Class A common stock will be made by our Board of Directors and will depend upon our financial condition, results of operations, cash flow, long-term prospects and any other matters that our Board of Directors deem relevant.

We expect to pay a quarterly dividend on or about the 30th day following each fiscal quarter to holders of record of our Class A common stock on the last day of such quarter.

Capital Expenditures and Investments

In 2015, total capital expenditures were $380.5 million. We do not include capital expenditures at our projects held at our unconsolidated equity investments.

We expect to make investments in additional projects. Although we have no commitments to make any such acquisitions, we consider it reasonably likely that we may have the opportunity to acquire certain other Pattern Development projects under our Purchase Rights within the next 24 month period. We also evaluate, from time to time, third-party acquisition opportunities. We believe that we will have sufficient cash and revolving credit facility capacity to complete the funding of future construction commitments we may have, but this may be affected by any other acquisitions or investments that we make. To the extent that we make any such investments or acquisitions, we will evaluate capital markets and other corporate financing sources available to us at the time.

In addition, we will make investments from time to time at our operating projects. Operational capital expenditures are those capital expenditures required to maintain our long-term operating capacity. Capital expenditures for the projects are generally made at the project level using project cash flows and project reserves, although funding for major capital expenditures may be provided by additional project debt or equity. Therefore, the distributions that we receive from the projects may be made net of certain capital expenditures needed at the projects.

For the year ending December 31, 2016, we have budgeted $2.5 million for operational capital expenditures and $5.3 million for expansion capital expenditures.

Contractual Obligations

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs. See also Note 9, Long Term Debt, and Note 18, Commitments and Contingencies, in the notes to consolidated financial statements for additional discussion of contractual obligations.

The following table summarizes estimates of future commitments related to the various agreements that we have entered into (in thousands):

Contractual Obligations	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Revolving credit facility	$355,000	$—	$—	$—	$355,000
Convertible debt	—	—	225,000	—	225,000
Long term debt principal payments	47,613	112,143	135,830	947,861	1,243,447
Interest payments on debt instruments	52,417	98,924	90,124	252,390	493,855
Purchase, construction, and other commitments	20,661	1,982	1,145	5,605	29,393
Operating leases (1)	11,103	26,225	29,448	285,977	352,753
Service and maintenance agreements	56,802	92,604	65,705	146,981	362,092
Asset retirement obligations	—	—	—	42,197	42,197
Total	$543,596	$331,878	$547,252	$1,681,011	$3,103,737

(1) On February 3, 2016, the Company entered into a lease agreement for office facilities in Houston, Texas, effective July 2016, to replace the Pattern Development-leased office facilities which expires in June 2016. Total future commitments are included in operating leases in the table above.

Effective January 1, 2016, Pattern Development assigned to us all of Pattern Development's rights, title, commitments and interest under an office lease, dated as of September 9, 2009, with respect office space in San Francisco. As a result of this lease assignment, we assumed remaining rental commitments under the lease plus certain annual operating expense reimbursements and customary security deposits. Concurrently with the lease assignment, we entered into an extension through 2026 of the office lease, which previously terminated at the end of February 2017. Total future commitments are included in operating leases in the table above.

Off-Balance Sheet Arrangements

We are not a party to any off-balance sheet arrangements.

Description of Credit Agreements

Consolidated Credit Agreements

Revolving Credit Facility

On September 28, 2015 and November 20, 2015, certain of our subsidiaries entered into amendments to our Amended and Restated Credit and Guaranty Agreement which increased our available limit under our existing revolving corporate credit facility from $350.0 million to $500.0 million, and added two new lenders to the credit facility ("Revolving Credit Facility"). The Revolving Credit Facility has a four-year term and is comprised of a revolving loan facility, a letter of credit facility and a swing-line facility. The Revolving Credit Facility is secured by pledges of the capital stock and ownership interests in certain of our holding company subsidiaries.

As of December 31, 2015, letters of credit of $27.2 million have been issued under the Revolving Credit Facility and we have an outstanding drawn loan balance of $355.0 million under the Revolving Credit Facility.

Interest Rate and Fees

The loans under our Revolving Credit Facility are either base rate loans or Eurodollar rate loans. The base rate loans accrue interest at the fluctuating rate per annum equal to the greatest of the (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the

Eurodollar rate that would be in effect for a Eurodollar rate loan with an interest period of one month plus 1.0%, plus an applicable margin ranging from 1.25% to 1.75% (corresponding to applicable leverage ratios of the borrower). The Eurodollar rate loans accrue interest at a rate per annum equal to LIBOR, as published by Reuters plus an applicable margin ranging from 2.25% to 2.75% (corresponding to applicable leverage ratios of the borrower). Under the Revolving Credit Facility, we pay a revolving commitment fee equal to the average of the daily difference between revolving commitments and the total utilization of revolving commitments times 0.50%. We also pay letter of credit fees.

Maintenance Covenants

Our Revolving Credit Facility requires the subsidiary borrowers to maintain a leverage ratio (the ratio of borrower debt to borrower cash flow) that does not exceed 5.50:1.00 and an interest coverage ratio (the ratio of borrower cash flow to borrower interest expense) that is not less than 1.75:1.00.

Distribution Conditions

Certain of our subsidiaries are subject to usual and customary affirmative and negative covenants under our Revolving Credit Facility. Specifically, with limited exceptions, such subsidiaries are prohibited from distributing funds to us unless the following conditions are met: (i) no event of default under the corporate credit facility has occurred and is continuing or would be caused by such distribution and (ii) the corporate credit facility borrowers are in compliance with the leverage ratio test and the interest coverage ratio test, both before and after giving effect to such declaration.

Prepayments, Certain Covenants and Events of Default

Our Revolving Credit Facility also has customary covenants, prepayment provisions and events of default.

Convertible Senior Notes Indenture

On July 28, 2015, we completed an unregistered Rule 144A offering (the "Notes Offering") of $225 million of convertible senior notes ("2020 Notes") under an indenture (the "Indenture") among us, Pattern US Finance Company LLC, as guarantor, and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"). The 2020 Notes bear interest at a rate of 4.00% per annum from and including July 28, 2015, payable semiannually in arrears on January 15 and July 15 of each year, beginning on January 15, 2016. The 2020 Notes will mature on July 15, 2020, unless repurchased or converted in accordance with their terms prior to such date.

We used the net proceeds from the 2020 Notes for the repayment of a portion of the outstanding indebtedness incurred in connection with our purchase of interests in the K2, Lost Creek and Post Rock wind projects, the acquisition of non-controlling interests in the Gulf Wind project, the prepayment of Gulf Wind project level indebtedness and general corporate purposes.

The 2020 Notes are unsecured obligations and are guaranteed on a senior unsecured basis by the Pattern US Finance Company LLC. The 2020 Notes are convertible into shares of the our Class A common stock at an initial conversion rate of 35.4925 Class A shares per $1,000 principal amount of the 2020 Notes. Conversions of the 2020 Notes will be settled, at our election, in cash, Class A shares or a combination thereof.

Upon a fundamental change (as defined in the Indenture), holders of the 2020 Notes may require us to repurchase all or part of their 2020 Notes at a fundamental change repurchase price in cash equal to 100% of the principal amount of the 2020 Notes to be repurchased, plus any accrued and unpaid interest to, if any, but excluding, the fundamental change repurchase date. In addition, if certain fundamental changes occur, we may be required in certain circumstances to increase the conversion rate for any 2020 Notes converted in connection with such fundamental changes by a specified number of Class A shares as set forth in the Indenture. The 2020 Notes are not redeemable at our option prior to maturity.

The Indenture contains customary terms and covenants, including that upon certain events of default occurring and continuing, either the Trustee or the holders of not less than 25% in aggregate principal amount of the 2020 Notes then outstanding may declare the unpaid principal of the 2020 Notes and accrued and unpaid interest, if any, thereon immediately due and payable. In the case of certain events of bankruptcy, insolvency or reorganization relating to us, the principal amount of the 2020 Notes together with accrued and unpaid interest, if any, thereon will automatically become and be immediately due and payable.

The 2020 Notes have not been, and will not be, registered under the Securities Act. The 2020 Notes may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act.

Hatchet Ridge Lease Financing

In December 2010, Hatchet Ridge as lessee, entered into two participation agreements, each for a 50% undivided interest in the Hatchet Ridge project, to implement a first lien lease financing, or the "Hatchet Ridge Leveraged Lease Financing," with each of Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B, each an owner lessor, Wells Fargo Delaware Trust Company National Association, as the owner trustee, MetLife Renewables Holding, LLC, as owner participant, and Wilmington Trust Company, as trustee under each lease indenture, and Credit Agricole Corporate and Investment Bank, as PPA letter of credit provider.

The financing was structured as two sale-leaseback transactions, each for a 50% undivided interest in the Hatchet Ridge project. Borrowings under each lease financing were used to refinance the construction financing for the Hatchet Ridge wind project. Pursuant to the sale-leaseback financings (i) MetLife Renewables Holding, LLC funded an equity investment in the Hatchet Ridge wind project, (ii) Hatchet Ridge sold an undivided interest in the Hatchet Ridge wind project to Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B, each a "Hatchet Ridge Undivided Interest," for a purchase price and Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B each leased their respective undivided interest back to Hatchet Ridge, (iii) Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B each sold lease notes to Wilmington Trust Company, as pass-through trustee, and (iv) Wilmington Trust Company entered into a pass-through trust agreement with Hatchet Ridge, pursuant to which Wilmington Trust Company used the proceeds of the sale of certificates to MetLife Renewables Holding, LLC to purchase the lease notes from Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B, respectively.

In addition, Credit Agricole Corporate and Investment Bank and Hatchet Ridge entered into a letter of credit and reimbursement agreement, or the "Hatchet Ridge LC Agreement," pursuant to which Credit Agricole Corporate and Investment Bank issued a PPA letter of credit to the power purchaser as payment security for Hatchet Ridge's obligations under the PPA. In the event of a draw under the PPA letter of credit that is not reimbursed by Hatchet Ridge, such amount becomes a PPA letter of credit loan. Each of Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B entered into a PPA letter of credit guarantee pursuant to which Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B, respectively, guarantee Hatchet Ridge's obligations to repay any draws under the PPA letter of credit and any amounts owed to Credit Agricole Corporate and Investment Bank under the Hatchet Ridge LC Agreement.

In addition, as partial consideration for the purchase price, Hatchet Ridge Wind 2010-A and Hatchet Ridge 2010-B each issued a note in favor of Hatchet Ridge in an amount of $40.1 million secured by a right to receive Hatchet Ridge Wind 2010-A and Hatchet Ridge Wind 2010-B's respective cash grant from the U.S. Treasury. The cash grant notes were fully paid once the cash grant proceeds were received from the U.S. Treasury. The financing is non-recourse to us.

Interest Rate

Our effective annual interest rate under the Hatchet Ridge Leveraged Lease Financing is approximately 1.43%.

Distribution Conditions

Hatchet Ridge may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) the reserves and other accounts are fully funded; (ii) there are no PPA letter of credit loans outstanding; (iii) no lease event of default has occurred and is continuing and (iv) the rent service coverage ratio is equal to or greater than 1.20:1.00.

Prepayments, Certain Covenants and Events of Default

The financing documents contain a broad range of covenants that, subject to certain exceptions, restrict Hatchet Ridge's ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay distributions and change its business. Hatchet Ridge may redeem the lease notes, in whole, at its option, at any time on or after December 14, 2015, and, in certain circumstances, must redeem the lease notes, in whole, at a price that includes a make whole premium. In addition, in certain circumstances, the note securing the PPA letter of credit loan is subject to mandatory redemption, in whole.

St. Joseph Amended Credit and Security Agreement

In November 2015, St. Joseph, terminated its existing construction and term loan and entered into a credit agreement or the "St. Joseph Credit Agreement." The St. Joseph Credit Agreement provides C$219.0 million in non-revolving term loan borrowings used for the purpose of repaying a prior construction and term lender and cover transaction costs which will mature in November 2033. The St. Joseph Credit Agreement also provides for a revolving letter of credit facility in the amount of C$25.0 million to support an operations and maintenance reserve letter of credit facility in an amount of C$8.5 million, a debt service reserve letter of credit facility in an amount of C$12.0 million and a power purchase agreement security letter of credit facility in an amount of C$4.5 million, which we collectively refer to as the "St. Joseph Letter of Credit Facility." The St. Joseph Credit Agreement also provides for an interest hedge facility. As of December 31, 2015, C$218.9 million, or as translated to U.S. dollar approximately $158.2 million, of indebtedness was outstanding under the St. Joseph Credit Agreement, all of which was outstanding under the term loan. The financing is limited recourse to us.

Interest Rate and Fees

The term loan is available either as a prime rate loan or Canadian Dealer Offered Rate, or "CDOR" loan, and accrues interest at the prime rate or CDOR (as applicable), plus the applicable margin. Prime rate loans accrue interest at a rate per annum equal to the sum of the prime rate in effect from time to time plus 0.625% (increasing by 0.125% every 3 years). CDOR loans accrue interest at a rate per annum equal to the sum of CDOR for the applicable interest period plus 1.625% (increasing by 0.125% every 3 years). After taking into consideration our fixed-for-floating rate swaps on 90% of the loan commitment, our estimated effective annual interest rate on the term loan is approximately 3.84%.

Distribution Conditions

St. Joseph may distribute excess cash flows to its owners provided that specified distribution conditions are met. The distribution conditions include, among other things, that: (i) there are no letter of credit loans outstanding; (ii) the first payment of principal shall have occurred; (iii) no default or inchoate default has occurred and such distribution will not result in an event of default; and (iv) the annual debt service coverage ratio is equal to or greater than 1.20:1.00.

Prepayments, Certain Covenants and Events of Default

The St. Joseph Credit Agreement contains a broad range of covenants that, subject to certain exceptions, limit St. Joseph’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. St. Joseph may voluntarily prepay the facility, in whole or in part, at any time without premium or penalty except for liquidation costs or interest fix fees, as applicable, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Spring Valley Credit Facilities

In August 2011, Spring Valley entered into a financing agreement, or the "Spring Valley Financing Agreement." The Spring Valley Financing Agreement currently provides for up to approximately $199.7 million in borrowings and is expected to mature in March 2031. Borrowings under the Spring Valley Financing Agreement were used to finance the construction of the Spring Valley wind project and consisted of a cash grant bridge loan of up to $53.3 million, a construction loan of up to $178.9 million, an operations and maintenance reserve letter of credit facility in an amount up to $5.4 million, a debt service reserve letter of credit facility in an amount up to $9.1 million and a PPA letter of credit facility in an amount up to $6.3 million. Additionally, the $53.3 million cash grant bridge loan that was borrowed under the Spring Valley Financing Agreement was repaid from an ITC cash grant Spring Valley received following the commencement of commercial operations. The construction loan converted into the term loan upon completion of construction of the Spring Valley wind project and satisfaction of certain other specified conditions.

On October 20, 2015, a re-pricing of the financing agreements related to the Spring Valley facility was consummated. Pursuant to the terms of the re-pricing, the interest rate on the term loan for the facility was reduced from LIBOR plus 2.38% to LIBOR plus 1.75% (increasing by 0.125% every four years). A prepayment of $29.7 million towards the outstanding principal balance on Spring Valley's term loan facility was also made. In addition, as part of the re-pricing, $22.5 million of project reserve requirements were eliminated.

As of December 31, 2015, approximately $132.7 million of indebtedness was outstanding under the Spring Valley Financing Agreement, all of which was outstanding under the term loan. We have agreed to indemnify Spring Valley in the event of disallowance of the ITC cash grant. Other than the indemnification, the financing is non-recourse to us.

Interest Rate and Fees

Term loans and letter of credit loans that are LIBOR loans accrue interest at LIBOR plus a margin of 1.75% per annum, and those that are base rate loans accrue interest at the base rate plus a margin of 0.75% per annum. Each such margin is increased by 0.125% on each of the fourth (4th), eighth (8th) and twelfth (12th) anniversary of October 20, 2015. Our effective annual interest rate, after taking into account our fixed-for-floating LIBOR swaps, is approximately 4.89%.

Spring Valley is also required to pay quarterly commitment fees on the operations and maintenance reserve letter of credit commitment, the debt service reserve letter of credit loan commitment and the PPA letter of credit loan commitment.

Distribution Conditions

Spring Valley may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that distributions may be made only if: (i) the initial repayment date and the term conversion of the construction loan have occurred; (ii) the reserves and other accounts are fully funded; (iii) all outstanding cash grant bridge loans, letter of credit loans and other letter of credit reimbursement obligations have been repaid; (iv) any mandatory prepayment required as a result of the occurrence of an upwind array event has been made; (v) no default or event of default has occurred; (vi) the annual debt service coverage ratio is equal to or greater than 1.20:1.00; and (vii) a satisfactory ruling or settlement has occurred in connection with the litigation challenging the Bureau of Land Management Rights-of-Way.

Prepayments, Certain Covenants and Events of Default

The Spring Valley Financing Agreement contains a broad range of covenants that, subject to certain exceptions, restrict Spring Valley’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. Spring Valley may voluntarily prepay the facility, in whole or in part, at any time without premium or penalty (except for liquidation costs and interest fix fees, if applicable) and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Santa Isabel Senior Financing Agreement

In October 2011, Pattern Santa Isabel LLC, or "Santa Isabel," entered into a first lien senior secured financing agreement, or the "Santa Isabel Financing Agreement." The Santa Isabel Financing Agreement provides up to approximately $192.4 million in borrowings. Borrowings under the Santa Isabel Financing Agreement were used to finance the construction of the Santa Isabel wind project and include a cash grant bridge loan of up to $57.5 million and a construction loan of up to $119.0 million. The cash grant bridge loan was repaid from an ITC cash grant that Santa Isabel received in June 2013. The construction loan converted into a term loan in May 2013.

The Santa Isabel Financing Agreement also provides for an operations and maintenance reserve loan facility in an amount up to $6.7 million, debt service reserve loan facility in an amount up to $6.2 million and a PPA collateral facility in an amount up to $3.0 million. As of December 31, 2015, approximately $110.0 million of indebtedness was outstanding under the Santa Isabel Financing Agreement. We agreed to indemnify Santa Isabel in the event of disallowance of the ITC cash grant. Other than the indemnification, the financing is non-recourse to us.

Interest Rate and Fees

The operations and maintenance reserve loans, debt service reserve loans and PPA collateral loans are either base rate loans or LIBOR loans. Reserve loans that are LIBOR loans accrue interest at LIBOR plus 2.00% per annum, and reserve loans that are base rate loans accrue interest at the greater of (i) the prime rate and (ii) the federal funds rate plus 0.50%, plus 1.00% per annum, but increase by 12.5 basis points every three years after the earlier of March 31, 2013 and term conversion. Construction loans and term loans are fixed rate loans and accrue interest at 1.94% per annum plus a margin of 2.625%, for a total annual interest rate of 4.57%.

Santa Isabel is also required to pay quarterly commitment fees on the operations and maintenance reserve loan commitment the debt service reserve loan commitment, the PPA collateral commitment and PPA collateral advance fees.

Distribution Conditions

Santa Isabel may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) distributions may be made only following the last banking day of 2012; (ii) the occurrence of the term conversion of the construction loan; (iii) the reserves and other accounts are fully funded; (iv) all outstanding operations and maintenance reserve loans, debt service reserve loans and PPA collateral loans have been repaid and all PPA collateral reimbursement obligations have been paid; (v) any mandatory prepayment required as a result of the occurrence of an upwind array event has been made; (vi) no default or event of default has occurred; and (vii) the annual debt service coverage ratio is equal to or greater than 1.20:1.00.

Prepayments, Certain Covenants and Events of Default

The Santa Isabel Financing Agreement contains a broad range of covenants that, subject to certain exceptions, restrict Santa Isabel's ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. Santa Isabel may, with certain exceptions, voluntarily prepay the facility, in whole or in part, at any time without premium or penalty except for liquidation costs and make-whole payments with respect to the fixed rate loans, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Ocotillo Senior Financing Agreement

Ocotillo entered into a first lien senior secured financing agreement, or the "Ocotillo Financing Agreement," with a group of commercial banks and a development bank in October 2012. The commercial bank tranche was re-priced in October 2014. The Ocotillo Financing Agreement provides up to approximately $467.3 million in borrowings. Borrowings under the Ocotillo Financing Agreement were used to finance the construction of the Ocotillo wind project and are comprised of a network upgrade bridge loan of up to approximately $56.6 million and two construction loans of up to approximately $351.5 million. The two construction loans consist of a development bank tranche of $110.0 million and a commercial bank tranche of up to approximately $241.5 million and mature 20 years and 7 years after the occurrence of term conversion, respectively. The network upgrade bridge loan was repaid from reimbursements by the interconnecting utility of reimbursable network upgrade costs. The construction loans converted into term loans upon completion of construction of the Ocotillo wind project.

The Ocotillo Financing Agreement also provides for an operations and maintenance reserve letter of credit facility in an amount up to $10.5 million, a debt service reserve letter of credit facility in an amount up to $22.0 million and a PPA letter of credit facility in an amount up to $26.7 million. We have agreed to indemnify Ocotillo in the event of disallowance of the ITC cash grant and for certain legal expenses in connection with certain pending legal proceedings at the project level.

Interest Rate and Fees

The commercial bank tranche construction loans and the term loans are either base rate loans or LIBOR loans, and accrue interest at the base rate or LIBOR (as applicable), plus the applicable margin. Base rate loans accrue interest at the greatest of (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the LIBOR plus 1.00%. The applicable margin for the commercial bank tranche construction loan was 3.00%. The applicable margin for development bank tranche construction and term loans is 2.10%. Our estimated annual effective interest rate on the development bank tranche, after taking into consideration our fixed-for-floating rate swaps on 90% of the loan commitment, is approximately 4.37%. In October 2014, the Ocotillo Financing Agreement was amended to include a margin rate decrease of 1.0% for the commercial bank tranche. The applicable margin for commercial bank tranche term loans is now, after the re-pricing, 1.75% and increases by 0.25% on the fourth anniversary of the term conversion date. The effective annual interest rate for the commercial bank tranche term loan, after taking into consideration our fixed-for-floating rate swaps on 90% of the loan commitment, is approximately 3.77%. The applicable margin for each of the PPA, the operations and maintenance and the debt service reserve letter of credit loans is now, after the re-pricing, 1.75%, respectively, from term conversion until the 4th anniversary of the term conversion date, and 2.00%, thereafter. As of December 31, 2015, approximately $312.6 million of indebtedness was outstanding under the Ocotillo Financing Agreement.

Ocotillo is also required to pay quarterly commitment fees on the commercial bank tranche construction loan commitment, the development bank tranche construction loan commitment, and each of the LC commitments.

Distribution Conditions

Ocotillo may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include, among other things, that: (i) there are no letter of credit loans or network upgrade bridge loans outstanding; (ii) the term conversion of the construction loans has occurred; (iii) the multipurpose reserve account is fully funded; (iv) no default or inchoate default has occurred and such distribution will not result in an event of default; and (v) the annual debt service coverage ratio is equal to or greater than 1.20:1.00.

Prepayments, Certain Covenants and Events of Default

The Ocotillo Financing Agreement contains a broad range of covenants that, subject to certain exceptions, limit Ocotillo’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. Ocotillo may voluntarily prepay the facility, in whole or in part, at any time without premium or penalty except for liquidation costs or interest fix fees, as applicable, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Currently, Ocotillo’s right of way grant to utilize federal land is the subject of litigation. We do not believe this matter will have a material adverse effect on our business, but the Ocotillo Financing Agreement contains provisions that provide lender protection to the extent that the litigation causes or would reasonably be expected to cause a material degradation in Ocotillo’s prospects, either though reduced revenues or increased costs. Such provisions include limited cash traps and mandatory pre-payments, if needed.

El Arrayán Senior Financing Agreement

In May 2012, El Arrayán entered into a first lien senior secured credit agreement, or the "El Arrayán Credit Agreement." The El Arrayán Credit Agreement provides up to approximately $225.0 million in borrowings. Borrowings under the El Arrayán Credit Agreement were used to finance the construction of the El Arrayán wind project and are comprised of a commercial tranche of up to $100.0 million and an export credit agency tranche provided by Eksport Kredit Fonden of Denmark, or the "EKF Tranche," of up to $110.0 million, and letters of credit facilities totaling up to $15 million. The construction loan converted into a term loan upon completion of construction of El Arrayán on August 14, 2014.

As of December 31, 2015, approximately $204.6 million of indebtedness was outstanding under the El Arrayán Credit Agreement. The financing is non-recourse to us.

Interest Rate and Fees

The commercial tranche construction and term loans are, with certain exceptions, LIBOR loans and accrue interest at LIBOR plus 2.75% per annum from the closing until the sixth anniversary of closing, 3.00% from the sixth anniversary to the tenth anniversary of closing, 3.25% from the tenth anniversary to the fourteenth anniversary of closing, and 3.50% after the fourteenth anniversary of closing. The EKF Tranche term loans accrue interest at a fixed rate of 5.56%, in each case, plus a margin of 0.25% from the sixth anniversary to the tenth anniversary of the closing, 0.50% from the tenth anniversary to the fourteenth anniversary of closing, and 0.75% after the fourteenth anniversary of closing. After taking into consideration our fixed-for-floating rate swaps on 95.8% of the commercial tranche term loan, our estimated effective annual interest rate on the term loan is approximately 5.65%.

El Arrayán is also required to pay semi-annual commitment fees on the letter of credit commitments. El Arrayán also pays arranger fees and agency fees.

Distribution Conditions

El Arrayán may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) the date is six months after term conversion or September 30, 2014 has occurred; (ii) the first repayment date has occurred, (iii) no default or event of default has occurred and is continuing; (iv) the reserve accounts are fully funded or the applicable letters of credit have been issued and are available for drawing; and (v) the debt service coverage ratio for the two preceding semi-annual periods is not less than 1.20:1:00.

Prepayments, Certain Covenants and Events of Default

The El Arrayán Credit Agreement contains a broad range of covenants that, subject to certain exceptions, restrict El Arrayán’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. El Arrayán may, with certain exceptions, voluntarily prepay the facility at any time without premium or penalty except for breakage costs, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Lost Creek Senior Financing Agreement

On April 5, 2011, prior to the project’s acquisition by us, Lost Creek, entered into an Amended and Restated Credit Agreement for an aggregate term loan of $144.0 million, maturing on March 31, 2021. In connection with the term loan, Lost Creek entered into interest rate swaps for the term of the loan to hedge its exposure to variable interest rates and to hedge its exposure to re-financing rate risk.

On September 3, 2015, Lost Creek entered into a Second Amended and Restated Credit Agreement, or the "Lost Creek Financing Agreement," which, among other things, (a) added a revolver facility, or the "Lost Creek Revolving Credit Facility," of up to $10.7 million (up to $3 million for revolving loans to pay operation and maintenance expenses and up to $7.7 million for revolving loans to pay debt service and related payments), (b) extended the tenor of the loans from March 2021 to September 2027 and (c) reduced the applicable margins to the amounts described below.

Interest Rate and Fees

The term loans under the Lost Creek Revolving Credit Facility are available either as base rate loans or Eurodollar rate loans. The base rate loans would accrue interest at (a) the fluctuating rate per annum equal to the greatest of the (i) the prime rate and (ii) the federal funds rate plus 0.50%; plus (b) the Lost Creek Applicable Margin, as defined below, less 0.75%. The Eurodollar rate loans would accrue interest at (a) a rate per annum equal to the rate per annum determined by the administrative agent to be equal to the quotient obtained by dividing (i) LIBOR, as published by Reuters by (ii) 1 minus the rate at which reserves are required by the Board of Governors of the Federal Reserve System to be held for such Eurodollar loan; plus (b) the Lost Creek Applicable Margin. The "Lost Creek Applicable Margin" is 1.65% (up to year 3), 1.775% (year 4 through year 7 inclusive), or 1.9% (year 8 onwards). After taking into consideration our fixed-for-floating rate swaps on the term loan commitment, our estimated effective current annual interest rate on the term loan is approximately 6.49%.

Lost Creek is also required to pay quarterly commitment fees on the Lost Creek Revolving Credit Facility at the Lost Creek Applicable Margin.

Distribution Conditions

Lost Creek may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) no default or event of default has occurred; (ii) the annual debt service coverage ratio is equal to or greater than 1.20:1.00; (iii) no loans are outstanding under the Lost Creek Revolving Credit Facility; (iv) there are sufficient funds in a property tax reserve; (v) no cash sweeps relating to an upwind array event are in effect; (vi) the distribution date certificate has been provided; and (vii) the distribution occurs in April or October.

Prepayments, Certain Covenants and Events of Default

The Lost Creek Financing Agreement contains a broad range of covenants that, subject to certain exceptions, restrict Lost Creek’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. Lost Creek may, with certain exceptions, voluntarily prepay the facility, in whole or in part, at any time without premium or penalty except for liquidation costs and make-whole payments with respect to the interest rate swaps, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

As of December 31, 2015, approximately $110.8 million of indebtedness was outstanding under the Lost Creek Financing Agreement. The financing is non-recourse to us.

Logan’s Gap Letter of Credit and Reimbursement Agreement

In December 2014, Logan’s Gap entered into a Letter of Credit and Reimbursement Agreement pursuant to which, following the completion of construction of the project and the repayment of the construction financing loan for the project, a letter of credit of $15.0 million was issued in favor of the power purchaser. The letter of credit facility is non-recourse to us.

Interest Rate and Fees

Amounts drawn under the Letter of Credit issued under the Letter of Credit and Reimbursement Agreement convert into loans unless repaid. The loans are due and payable upon the earlier of (i) two years after the making of the loan or (ii) December 31, 2025. The loans are either base rate loans or LIBOR loans. Loans that are LIBOR loans accrue interest at LIBOR plus 2.0% per annum, and loans that are base rate loans accrue interest at the greater of (i) the prime rate or (ii) the federal funds rate plus 0.50% plus 1.00% per annum.

Logan’s Gap is also required to pay quarterly commitment fees on undrawn amounts of the construction loan commitment and the letter of credit loan commitments.

Prepayments, Certain Covenants and Events of Default

The Logan’s Gap Letter of Credit and Reimbursement Agreement contains standard covenants that, among other things and subject to certain exceptions, restrict Logan’s Gap’s ability to incur debt, grant liens, sell or lease certain assets, dissolve and make distributions.

Credit Agreements for Equity Method Investments

Below is a summary of our proportion of debt, net of deferred financing costs, in unconsolidated investments, as of December 31, 2015 (in thousands):

	Total Project Debt	Percentage of Ownership	Our Portion of Unconsolidated Project Debt
South Kent	$466,475	50.0 %	$233,238
Grand	270,945	45.0 %	121,925
K2	580,100	33.3 %	193,362
Unconsolidated investments - debt	$1,317,520		$548,525

South Kent Senior Financing Agreement

In March 2013, South Kent Wind LP entered into a first lien senior secured financing agreement, or the "South Kent Financing Agreement." The South Kent Financing Agreement provides up to approximately C$683.8 million in borrowings. Borrowings under the South Kent Financing Agreement were used to finance the construction of the South Kent project and were comprised of a construction loan of up to approximately C$683.8 million. The construction loan converted into a term loan following completion of construction of the South Kent project. The term loan matures seven years after the occurrence of the term conversion. The financing is non-recourse to us. As of December 31, 2015, the outstanding balance of the loan was approximately C$645.5 million.

The South Kent Financing Agreement also provides for operations and maintenance reserve letter of credit facility in an amount up to C$12.0 million and a debt service reserve letter of credit facility in an amount up to C$40.6 million, which we collectively refer to as the "letter of credit loans."

Following term conversion of the construction loan facility which occurred on August 28, 2014, the South Kent Financing Agreement was amended to account for administrative amendments with respect to landowner payment and petty cash accounts (September 30, 2014) and to address administrative procedures relating to distributions of revenue received from the IESO (November 20, 2015). On August 20, 2015, an amendment was executed to give effect to amendments to the real estate interests related to a portion of the transmission line assets of the project.

Interest Rate and Fees

The construction loan, the letter of credit loans, and, after the term conversion, the term loans are either prime rate loans or Canadian Dealer Offered Rate, or "CDOR" loans, and accrue interest at the prime rate or CDOR (as applicable), plus the applicable margin. Prime rate loans accrue interest at a rate per annum equal to the sum of the Canadian Prime Rate in effect from time to time plus 1.50% (increasing to 1.75% after the fourth anniversary of term conversion). CDOR loans accrue interest at a rate per annum equal to the sum of CDOR for the applicable interest period plus 2.50% (increasing to 2.75% after the fourth anniversary of term conversion). After taking into consideration our fixed-for-floating rate swaps on 90% of the loan commitment, our estimated effective annual interest rate on the term loan is approximately 5.58%.

South Kent Wind LP is also required to pay quarterly commitment fees on the construction loan commitment and each of the letter of credit loan commitments.

On May 7, 2015, an amendment was executed to give effect to a re-pricing of the South Kent term loan facility. Pursuant to the amendment, the applicable margin was amended for the term of the loan to the final maturity date to be 1.625% for CDOR loans and 0.625% for prime rate loans.

A fee of 70 basis points on the lenders' total aggregate commitment was paid to the lenders in connection with the foregoing, which was financed through an additional fee facility added to the South Kent Financing Agreement.

Distribution Conditions

South Kent Wind LP may distribute excess cash flows to its owners provided that specified distribution requirements are met. The distribution requirements include, among other things, that: (i) there are no letter of credit loans outstanding; (ii) the term

conversion of the construction loan has occurred; (iii) no default or inchoate default has occurred and such distribution will not result in an event of default; and (iv) the annual debt service coverage ratio is equal to or greater than 1.20:1.00.

Prepayments, Certain Covenants and Events of Default

The South Kent Financing Agreement contains a broad range of covenants that, subject to certain exceptions, limit South Kent Wind LP's ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay dividends and change its business. South Kent Wind LP may voluntarily prepay the facility, in whole or in part, at any time without premium or penalty except for liquidation costs or interest fix fees, as applicable, and, in certain circumstances, must make mandatory prepayments of loans under the facility.

Grand Credit Agreement

In September 2013, Grand entered into a credit agreement or the "Grand Credit Agreement." The Grand Credit Agreement provides up to C$395.4 million in construction loan borrowings and up to C$37.0 million of letters of credit under a letter of credit facility. Construction loan borrowings were used to finance the construction of the Grand wind power project, which was completed in December 2014, and converted to a term loan on July 29, 2015. The term loan will mature seven years after the term conversion date of the construction loan. The outside maturity date of the term loan and the letter of credit facility is no later than June 30, 2022. Letters of credit under the letter of credit facility can be issued in connection with debt service reserve requirements, O&M reserve requirements, and decommissioning requirements. As of December 31, 2015, C$374.9 million of indebtedness was outstanding under the Grand Credit Agreement, all of which was outstanding under the term loan and $0 was outstanding under the letter of credit facility. The financing is non-recourse to us.

Prior to term conversion, the Grand Credit Agreement was amended for minor administrative matters, including amendments signed on January 16, 2014 (to add additional leased lands to the collateral package) and on March 16, 2015 (to address administrative amendments to landowner payment and petty cash accounts).

Interest Rate and Fees

Loans are either prime rate loans or CDOR loans. If the construction loan is a prime rate loan it accrues interest at the greater of (i) lenders prime rate or (ii) 30-day CDOR plus 1%, plus an applicable margin of 1.25%. If the construction loan is a CDOR loan, it accrues interest at the applicable CDOR per interest period plus 2.25%. After conversion, if the term loan is a prime rate loan it will accrue interest at the greater of (i) lenders prime rate or (ii) 30-day CDOR plus 1%, plus an applicable margin of 1.25%. If the term loan is a CDOR loan, it will accrue interest at the applicable CDOR per interest period plus 2.25%. The letter of credit loans are drawn as prime rate borrowings that subsequently convert to CDOR loans and accrue the same interest as the construction or term loans, as the case may be.

Grand is also required to pay quarterly commitment fees on undrawn amounts of the construction loan commitment and the letter of credit loan commitment.

Distribution Conditions

Grand may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) term conversion shall have occurred, (ii) the first payment of scheduled principal shall have been paid by Grand, (iii) the debt service coverage ratio at the end of Grand's immediately preceding fiscal quarter is 1.2:1.00 or greater, (iv) all outstanding letter of credit loans shall have been paid; and (vi) no default or event of default shall have occurred and is continuing or would result from the distribution.

Prepayments, Certain Covenants and Events of Default

The Grand Credit Agreement contains standard covenants that, among other things and subject to certain exceptions, restrict Grand's ability to incur debt, grant liens, sell or lease certain assets, transfer equity interests, dissolve, make distributions and change its business. Grand may voluntarily prepay the construction or term loan, in whole or in part, at any time without premium or penalty, provided it shall have first prepaid any outstanding letter of credit loans, and, in certain circumstances, must make mandatory prepayments of the loans.

K2 Credit Agreement
K2 is an Ontario limited partnership owned equally by Pattern Canada Finance Company ULC and affiliates of Samsung Renewable Energy Inc. and Capital Power. K2 entered into a credit agreement on March 20, 2014, or the "K2 Credit Agreement," for the financing of the construction of the K2 wind project. The K2 Credit Agreement provided K2 with access to credit facilities of up to C$818.0 million in construction loan borrowings and up to C$60.5 million of letters of credit under a letter of credit facility.
The K2 project achieved commercial operation on May 29, 2015. The construction loan facility converted to a seven year term loan facility effective November 20, 2015. Letters of credit under the letter of credit facility can be issued in connection with debt service reserve requirements, O&M reserve requirements, and decommissioning requirements. As of December 31, 2015, C$802.7 million of indebtedness was outstanding under the K2 Credit Agreement, all of which was outstanding under the term loan. The financing is non-recourse to us.
Interest Rate and Fees
After conversion, if the term loan is a prime rate loan, it will accrue interest at the greater of (i) lenders prime rate or (ii) 30-day CDOR plus 1%, plus an applicable margin of 0.75%. If the term loan is a CDOR loan, it will accrue interest at the applicable CDOR per interest period plus an applicable margin of 1.75%. The letter of credit loans are drawn as prime rate borrowings that subsequently convert to CDOR loans and accrue the same interest as the construction or term loans, as the case may be.
K2 is also required to pay quarterly commitment fees on undrawn amounts of the construction loan commitment and the letter of credit loan commitment.
Distribution Conditions
K2 may distribute excess cash flows to its owner provided that specified distribution requirements are met. The distribution requirements include that: (i) term conversion shall have occurred, (ii) the first payment of scheduled principal shall have been paid by K2, (iii) the debt service coverage ratio at the end of K2's immediately preceding fiscal quarter is 1.2:1.00 or greater, (iv) all outstanding letter of credit loans shall have been paid; and (vi) no default or event of default shall have occurred and is continuing or would result from the distribution.
Prepayments, Certain Covenants and Events of Default
The K2 Credit Agreement contains standard covenants that, among other things and subject to certain exceptions, restrict K2's ability to incur debt, grant liens, sell or lease certain assets, transfer equity interests, dissolve, make distributions and change its business. K2 may voluntarily prepay the term loan, in whole or in part, at any time without premium or penalty, provided it shall have first prepaid any outstanding letter of credit loans, and, in certain circumstances, must make mandatory prepayments of the loans.
Tax Equity Partnership Agreements
Panhandle 1 Tax Equity Partnership Transaction
Panhandle 1 was 100% owned by our subsidiaries Panhandle B Member LLC, or the "Class B Member," and Panhandle Alternate B Member LLC (which subsequently transferred 100% of its interests in the project to the Class B Member). Pursuant to an Equity Capital Contribution Agreement dated August 19, 2013, upon completion of construction, various Class A equity investors, or the "Class A Equity Investors" or "Class A Members," and the Class B Member made equity capital contributions to Panhandle 1 and the Class B Member sold an interest in Panhandle 1, or "the Class A Member Interest," to the Class A Equity Investors in a tax equity partnership transaction, pursuant to which the Class A Members are entitled to receive allocations of cash distributions and tax items of Panhandle 1 that vary over time as described below. The Class B Members and the Class A Members agreed that the fair value of the Class A Member Interest was approximately 62% of the aggregate fair value of the sum of all equity interests in Panhandle 1. We currently own 100% of the existing Class B member interests in Panhandle 1 and our subsidiary, the Class B Member, is the managing member of Panhandle 1.
Allocation of Distributions
In accordance with the terms of the operating agreement of Panhandle 1, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or June 29, 2023, the Class A Members shall receive

approximately 21% of all distributions from Panhandle 1. If the flip point has not occurred by June 29, 2023, the Class A Members shall receive 100% of distributable cash. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Members will receive the remainder of all distributable cash. Distributions related to the sale of renewable energy credits (RECs) are made primarily to the Class B Members.

Allocation of Tax Items

Prior to the flip point, Panhandle 1’s tax items consisting of income, gain, loss and deductions, or the "Tax Items," are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Members. After the flip point, the Class A Members receive 5% of the Tax Items and the balance will be received by the Class B Members. Tax items related to the sale of RECs are allocated primarily to the Class B Member.

The Class A Member’s Right to Escrow Distributions

If the Class A Members suffer any losses or damages as the result of a breach of representation by the Class B Members or breach of covenant or other obligations by the Class B Member, in its capacity as managing member of Panhandle 1, the Class A Members may provide notice to the Class B Member and require that any distributions otherwise required to be paid to the Class B Members shall, instead, be paid to the Class A Members to cover any damages caused to the Class A Members. Any distributions that the Class B Member agrees to pay to the Class A Members are paid to the Class A Members to satisfy their damages. To the extent the parties do not agree on the damages caused to the Class A Members, the Class B Member’s distributions are required to be paid into escrow with a third party commercial bank. Such escrowed amounts will be released from escrow upon the joint instruction of both parties, or, following a judgment or court order settling the dispute between the parties.

Management of Panhandle 1

The project is managed by one of our subsidiaries. The Class A Members are not involved in the day-to-day management of the project. As is customary for transactions of this type, the managing member is required to obtain the Class A Members’ consent for certain major decisions concerning the project and set forth in the operating agreement of the project. Such major decisions include, for example, incurring indebtedness other than permitted indebtedness, encumbering project assets, sale of project assets, terminating material project documents, certain changes in method of accounting, merging and consolidating the project and such other major actions. In the event that the Class B Members become insolvent, dissolve or encounter a regulatory impediment preventing their ownership of the project, the Class A Members have an option to buy out the Class B Members’ interests in the project.

Panhandle 2 Tax Equity Partnership Transaction

Panhandle 2 was 100% owned by our subsidiary Panhandle B Member 2 LLC, the "Class B Member." Pursuant to an Equity Capital Contribution Agreement dated December 20, 2013, various Class A equity investors, the "Class A Equity Investors" or "Class A Members," and the Class B Member agreed to make equity capital contributions to Panhandle 2 at the completion of construction, the Class B Member sold an interest, or the "Class A Member Interest," in Panhandle 2 to the Class A Equity Investors in a tax equity partnership transaction, pursuant to which the Class A Members are entitled to receive allocations of cash distributions and tax items of Panhandle 2 that vary over time as described below. The Class B Member and the Class A Members agreed that the fair value of Class A Member Interest was approximately 63% of the aggregate fair value of the sum of all equity interests in Panhandle 2. We currently own 100% of the existing Class B Member interests in Panhandle 2 and one of our subsidiaries is the managing member of Panhandle 2.

Allocation of Distributions

In accordance with the terms of the operating agreement of Panhandle 2, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 30, 2023, the Class A Members shall receive approximately 19% of all distributions from Panhandle 2. If the amount of distributions is below a determined schedule, the Class A Members shall receive 40% of distributable cash and the Class B Members shall receive the remainder of distributable cash. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A Members’ tax liabilities. In each case, the

Class B Members will receive the remainder of all distributable cash. Distributions related to the sale of renewable energy credits (RECs) are made primarily to the Class B Member.

Allocation of Tax Items
Prior to the flip point, Panhandle 2’s tax items consisting of income, gain, loss and deductions, or the "Tax Items," are allocated as follows: 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Members. After the flip point, the Class A Members receive 5%, and the balance will be received by the Class B Members. Tax items related to the sale of RECs are allocated primarily to the Class B Member.
The Class A Member’s Right to Escrow Distributions
If the Class A Members suffer any losses or damages as the result of a breach of representation by the Class B Member or breach of covenant or other obligations by the Class B Member, in its capacity as managing member of Panhandle 2, the Class A Members may provide notice to the Class B Member and require that any distributions otherwise required to be paid to the Class B Member shall, instead, be paid to the Class A Members to cover any damages caused to the Class A Members. Any distributions that the Class B Member agrees to pay to the Class A Members are paid to the Class A Members to satisfy their damages. To the extent the parties do not agree on the damages caused to the Class A Members, the Class B Member’s distributions are required to be paid into escrow with a third party commercial bank. Such escrowed amounts will be released from escrow upon the joint instruction of both parties, or, following a judgment or court order settling the dispute between the parties.
Management of Panhandle Wind Holdings
The project is managed by one of our subsidiaries. The Class A Members are not involved in the day-to-day management of the project. As is customary for transactions of this type, the managing member is required to obtain the Class A Members’ consent for certain major decisions concerning the project and set forth in the operating agreement of the project. Such major decisions include, for example, incurring indebtedness other than permitted indebtedness, encumbering project assets, sale of project assets, terminating material project documents, certain changes in method of accounting, merging and consolidating the project and such other major actions. In the event that the Class B Member becomes insolvent, dissolves or encounters a regulatory impediment preventing its ownership of the project, the Class A Members have an option to buy out the Class B Member’s interests in the project.
Logan’s Gap Tax Equity Partnership Transaction
Logan’s Gap was 100% owned by our subsidiary Logan’s Gap B Member LLC, or the "Class B Member." Pursuant to an Equity Capital Contribution Agreement dated September 18, 2015, upon completion of construction, various Class A equity investors, or the "Class A Equity Investors" or "Class A Members," and the Class B Member made equity capital contributions to Logan’s Gap and the Class B Member sold an interest in Logan’s Gap, or "the Class A Member Interest," to the Class A Equity Investors in a tax equity partnership transaction, pursuant to which the Class A Members are entitled to receive allocations of cash distributions and tax items of Logan’s Gap that vary over time as described below. The Class B Member and the Class A Members agreed that the fair value of the Class A Member Interest was approximately 65% of the aggregate fair value of the sum of all equity interests in Logan’s Gap. We currently own 100% of the existing Class B member interests in Logan’s Gap and our subsidiary, the Class B Member, is the managing member of Logan’s Gap.
Allocation of Distributions
In accordance with the terms of the operating agreement of Logan’s Gap, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or December 17, 2024, the Class A Members shall receive approximately 18% of all distributions from Logan’s Gap. If the amount of distributions is below determined thresholds, the Class A Members shall receive higher percentages of distributable cash, ranging from 28% to 100%. After the flip point, the Class A Members will receive 5.1% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Members will receive the remainder of all distributable cash. Distributions related to the sale of renewable energy credits (RECs) are made primarily to the Class B Members.
Allocation of Tax Items
Prior to the flip point, Logan’s Gap’s tax items consisting of income, gain, loss and deductions, or the "Tax Items," are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5.1% of the Tax Items and the balance will be

received by the Class B Member. Tax items related to the sale of RECs are allocated primarily to the Class B Member.

The Class A Member’s Right to Escrow Distributions

If the Class A Members suffer any losses or damages as the result of a breach of representation by the Class B Member or breach of covenant or other obligations by the Class B Member, in its capacity as managing member of Logan’s Gap, the Class A Members may provide notice to the Class B Member and require that any distributions otherwise required to be paid to the Class B Member shall, instead, be paid to the Class A Members to cover any damages caused to the Class A Members. Any distributions that the Class B Member agrees to pay to the Class A Members are paid to the Class A Members to satisfy their damages. To the extent the parties do not agree on the damages caused to the Class A Member, the Class B Member’s distributions are required to be paid into escrow with a third party commercial bank. Such escrowed amounts will be released from escrow upon the joint instruction of both parties, or, following a judgment or court order settling the dispute between the parties.

Management of Logan’s Gap

The project is managed by one of our subsidiaries. The Class A Members are not involved in the day-to-day management of the project. As is customary for transactions of this type, the managing member is required to obtain the Class A Members’ consent for certain major decisions concerning the project and set forth in the operating agreement of the project. Such major decisions include, for example, incurring indebtedness other than permitted indebtedness, encumbering project assets, sale of project assets, terminating material project documents, merging and consolidating the project and such other major actions. In the event that the Class B Member becomes insolvent, dissolves or encounters a regulatory impediment preventing its ownership of the project, the Class A Members have an option to buy out the Class B Member’s interests in the project.

Amazon Wind Farm Fowler Ridge Tax Equity Partnership Transaction

Amazon Wind Farm Fowler Ridge was 100% owned by our subsidiary Fowler Ridge IV B Member LLC, or the "Class B Member." Pursuant to an Equity Capital Contribution Agreement dated April 29, 2015, upon completion of construction, various Class A equity investors, or the "Class A Equity Investors" or "Class A Members," and the Class B Member made equity capital contributions to Amazon Wind Farm Fowler Ridge and the Class B Member sold an interest in Amazon Wind Farm Fowler Ridge, or "the Class A Member Interest," to the Class A Equity Investors in a tax equity partnership transaction, pursuant to which the Class A Members are entitled to receive allocations of cash distributions and tax items of Amazon Wind Farm Fowler Ridge that vary over time as described below. The Class B Member and the Class A Members agreed that the fair value of the Class A Member Interest was approximately 54% of the aggregate fair value of the sum of all equity interests in Amazon Wind Farm Fowler Ridge. We currently own 100% of the existing Class B member interests in Amazon Wind Farm Fowler Ridge and our subsidiary, the Class B Member, is the managing member of Amazon Wind Farm Fowler Ridge.

Allocation of Distributions

In accordance with the terms of the operating agreement of Amazon Wind Farm Fowler Ridge, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 30, 2025, the Class A Members shall receive approximately 35% of all distributions from Amazon Wind Farm Fowler Ridge. If the amount of distributions is below determined thresholds, the Class A Members shall receive higher percentages of distributable cash, ranging from 42% to 70%. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Members will receive the remainder of all distributable cash. Distributions related to the sale of renewable energy credits (RECs) are made primarily to the Class B Members.

Allocation of Tax Items

Prior to the flip point, Amazon Wind Farm Fowler Ridge's tax items consisting of income, gain, loss and deductions, or the "Tax Items," are allocated as follows: 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5% of the Tax Items and the balance will be received by the Class B Member. Tax items related to the sale of RECs not sold to the power purchaser under the power purchase agreement are allocated for the first 5 years primarily to the Class A Members and thereafter primarily to the Class B Member.

The Class A Member’s Right to Escrow Distributions

If the Class A Members suffer any losses or damages as the result of a breach of representation by the Class B Member or breach of covenant or other obligations by the Class B Member, in its capacity as managing member of Amazon Wind Farm Fowler Ridge, the Class A Members may provide notice to the Class B Member and require that any distributions otherwise required to be paid to the Class B Member shall, instead, be paid to the Class A Members to cover any damages caused to the Class A Member. Any distributions that the Class B Member agrees to pay to the Class A Members are paid to the Class A Members to satisfy their damages. To the extent the parties do not agree on the damages caused to the Class A Members, the Class B Member's distributions are required to be paid into escrow with a third party commercial bank. Such escrowed amounts will be released from escrow upon the joint instruction of both parties, or, following a judgment or court order settling the dispute between the parties.

Management of Amazon Wind Farm Fowler Ridge

The project is managed by one of our subsidiaries. The Class A Members are not involved in the day-to-day management of the project. As is customary for transactions of this type, the managing member is required to obtain the Class A Members' consent for certain major decisions concerning the project and set forth in the operating agreement of the project. Such major decisions include, for example, incurring indebtedness other than permitted indebtedness, encumbering project assets, sale of project assets, terminating material project documents, merging and consolidating the project and such other major actions. In the event that the Class B Member becomes insolvent, dissolves or encounters a regulatory impediment preventing its ownership of the project, the Class A Members have an option to buy out the Class B Member's interests in the project.

Post Rock Tax Equity Partnership Transaction

Our subsidiary, Pattern US Finance Company LLC acquired 100% of the equity ownership interests in Lincoln County Wind Project Holdco, LLC, or "Class B Member," from a subsidiary of Wind Capital Group, LLC. The Class B Member owns 100% of the existing Class B member interests in the owner of Post Rock and is the manager of Post Rock. Post Rock has also issued Class A membership interests, the owners, or the "Class A Members," of which are entitled to receive allocations of cash distributions and tax items of Post Rock that vary over time as described below.

Allocation of Distributions

In accordance with the terms of the operating agreement of Post Rock, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 20, 2023, the Class A Members shall receive 40% of all distributions from Post Rock. If the flip point has not occurred by November 20, 2023, then prior to the earlier of the flip point or November 20, 2027, the Class A Members shall receive 60% of all distributions from Post Rock. If the flip point has not occurred by November 20, 2027, the Class A Members shall receive 100% of all distributions from Post Rock until the flip point occurs. After the flip point, the Class A Members will receive 10% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash, provided that distributions related to certain payments under a Build Out Agreement between Post Rock and us are made to the Class A members.

Allocation of Tax Items

Prior to the flip point, Post Rock's tax items consisting of income, gain, loss and deductions, or the "Tax Items," are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 10% of the Tax Items and the balance will be received by the Class B Member. Tax items attributable to the liquidation of derivative contracts are allocated 4.95% to the Class A Members and 95.05% to the Class B Member.

The Class A Member's Right to Escrow Distributions

If the Class A Members suffer any losses or damages as the result of a breach of representation or breach of covenant or other obligations by the Class B Member, Pattern Operators LP, as the project administrator under the Project Administration Agreement with Post Rock (so long as the project administrator is an affiliate of the Class B Member), or Pattern Operators LP, as the operator under the O&M Management Agreement with respect to certain provisions under such O&M Management Agreement (so long as the operator is an affiliate of the Class B Member), the Class A Members may provide notice to the Class B Member and require that any distributions otherwise required to be paid to the Class B Member shall, instead, be paid to the Class A Members to cover any damages caused to the Class A Members. Any distributions that the Class B Member agrees to pay to the Class A Members are paid to the Class A Member to satisfy their damages. To the extent the parties do not agree on the damages caused to the Class A Members, the Class B Member's distributions are required to be paid into escrow with a third party commercial bank. Such escrowed amounts will be released from escrow upon the joint instruction of both parties, or, following a judgment or court order settling the dispute between the parties.

Management of Post Rock

The project is managed by one of our subsidiaries. The Class A Members are not involved in the day-to-day management of the project. As is customary for transactions of this type, the managing member is required to obtain the Class A Members' consent for certain major decisions concerning the project and set forth in the operating agreement of the project. Such major decisions include, for example, incurring indebtedness other than permitted indebtedness, encumbering project assets, sale of project assets, terminating material project documents, certain changes in method of accounting, merging and consolidating the project and such other major actions. In the event that the Class B Member becomes insolvent, dissolves, encounters a regulatory impediment preventing its ownership of the project, or is considered for federal income tax purposes to be the ultimate purchaser of electricity from the project, the Class A Members have an option to buy out the Class B Member's interests in the project.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on our consolidated historical financial statements that are included elsewhere in this Form 10-K, which have been prepared in accordance with U.S. GAAP. In applying the critical accounting policies set forth below, our management uses its judgment to determine the appropriate assumptions to be used in making certain estimates. These estimates are based on management's experience, the terms of existing contracts, management's observance of trends in the wind power industry, information provided by our power purchasers and information available to management from other outside sources, as appropriate. These estimates are subject to an inherent degree of uncertainty.

We use estimates, assumptions and judgments for certain items, including the calculation of our acquisitions, noncontrolling interest balances, and derivatives. These estimates, assumptions and judgments are derived and continually evaluated based on available information, experience and various assumptions we believe to be reasonable under the circumstances. To the extent these estimates are materially incorrect and need to be revised, our operating results may be materially adversely affected.

Acquisitions

Business Combinations, Asset Acquisitions, and Equity Method Investments

When we acquire a controlling interest in an entity deemed to be a business, the purchase is accounted for using the acquisition method, and the fair value of purchase consideration is allocated to the tangible and intangible assets acquired and liabilities assumed based on their estimated fair values. The excess, if any, of the fair value of purchase consideration over the fair value of these identifiable assets and liabilities is recorded as goodwill. Conversely, the excess, if any, of the net fair value of identifiable assets and liabilities over the fair value of purchase consideration is recorded as gain. Transaction costs associated with business combinations are expensed as incurred.

When we acquire assets and liabilities that do not constitute a business, the asset acquisition is measured based on its cost, including transaction costs. The cost of the acquisition is then allocated to the individual assets acquired and liabilities assumed on a relative fair value basis. Additionally, in the case of asset acquisitions, contingent consideration is generally recognized when the contingency is resolved. No goodwill or gain is recognized in an asset acquisition. Transaction costs are capitalized as a component of the cost of assets acquired.

When we acquire a noncontrolling interest in an entity that does not meet consolidation requirements of ASC 810, Consolidations of Variable Interest Entities, the investment is initially recognized as an equity method investment at cost. Transaction costs associated with our equity method investments are capitalized as part of the investment. Additionally, if the projects in which we hold these investments recognize an impairment under the provisions of ASC 360, we would record our impairment loss and would evaluate our investment for an other than temporary decline in value under ASC 323.

Significant judgment is required in determining the acquisition date fair value of the assets acquired and liabilities assumed using either an income, market, or cost based valuation method. The valuations require management to make significant estimates and assumptions. These estimates and assumptions are inherently uncertain, and as a result, actual results may differ from estimates. Significant estimates include, but are not limited to, revenue and operating expense growth, future expected cash flows, and discount rates.

For business combinations and asset acquisitions, during the measurement period, which is one year from the acquisition date, we may record adjustments to the assets acquired and liabilities assumed. Upon the conclusion of the measurement period, any subsequent adjustments are recorded to earnings.

The allocation of the purchase price directly affects the following items in our consolidated financial statements:

- The amount of purchase price allocated to the various tangible and intangible assets, liabilities and noncontrolling interests on our consolidated balance sheets;
- The amounts of purchase price allocated to the value of above-market and below-market power purchase agreement values are amortized to electricity sales over the remaining terms of each respective arrangement; and
- The period of time over which tangible and intangible assets are depreciated or amortized varies, and thus, changes in the amounts allocated to these assets will have a direct impact on our results of operations.

Noncontrolling Interests

Noncontrolling interests represent the portion of our net income (loss), net assets and comprehensive income (loss) that is not allocable to us and is calculated based on our ownership percentage, for certain projects.

For those projects where economic benefits are not allocated based on pro rata ownership percentage, we have determined that the appropriate methodology for calculating the noncontrolling interest balances that reflects the substantive economic arrangements in the operating agreements is a balance sheet approach using the hypothetical liquidation at book value (“HLBV”) method.

Under the HLBV method, the amounts reported as noncontrolling interests in the consolidated balance sheets represent the amounts third-party investors would hypothetically receive at each balance sheet reporting date under the liquidation provisions of the operating partnership agreements, assuming the net assets of our projects were liquidated at amounts determined in accordance with U.S. GAAP and distributed to the investors. Therefore, the noncontrolling interest balances in these projects are reported as a component of equity in the consolidated balance sheets.

The third-party interests in the results of operations for those projects using HLBV is determined as the difference in noncontrolling interests in the consolidated balance sheets at the start and end of each reporting period, after taking into account any capital transactions between our projects and the third-party investors.

Factors used in the HLBV calculation include U.S. GAAP income, taxable income, capital contributions and distributions, and the stipulated targeted equity investor return specified in the projects' operating agreements. Changes in these factors could have a significant impact on the amounts that investors would receive upon a hypothetical liquidation. The use of the HLBV methodology to allocate income to the noncontrolling interest holders may create volatility in our consolidated statements of operations as the application of HLBV can drive changes in net income or loss attributable to noncontrolling interests from quarter to quarter.

Derivatives

We enter into derivative transactions primarily for the purpose of reducing exposure to fluctuations in interest rates and electricity prices. We have entered into interest rate swap agreements and have designated certain of these derivatives as cash flow hedges of expected interest payments on variable rate debt. We may also enter into interest rate caps and electricity price derivatives. Currently, our interest rate cap and energy derivative agreements do not qualify for hedge accounting.

We recognize our derivative instruments at fair value in the consolidated balance sheets, unless the derivative instruments qualify for the “normal purchase normal sale” (“NPNS”) scope exception to derivative accounting. Accounting for changes in the fair value of a derivative instrument depends on whether the derivative instrument has been designated as part of a hedging relationship and on the type of hedging relationship.

For derivative instruments that are designated as cash flow hedges, the effective portion of change in fair value of the derivative is reported as a component of other comprehensive income (loss). Changes in the fair value of these derivatives are subsequently reclassified into earnings in the period that the hedged transaction affects earnings. The ineffective portion of change, if any, in fair value is recorded as a component of net income (loss) on the consolidated statements of operations. The change in fair value for undesignated derivative instruments is reported as a component of net income (loss) on the consolidated statements of operations. Certain of our electricity price instruments qualify for the NPNS scope exception and therefore are not accounted for as derivatives.

Energy prices are subject to wide swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate

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risk exists primarily on variable-rate debt for which the cash flows vary based upon movement in market prices. We do not hedge all of our commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, we use forward price curves derived from third-party models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward energy prices, interest rates, related volatility, counterparty creditworthiness, and duration of contracts. The assumptions used in the valuation models are critical and any changes in assumptions could have a significant impact on the estimated fair value of the contracts.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We have significant exposure to commodity prices, interest rates and foreign currency exchange rates, as described below. To mitigate commodity price and interest rate risks, we have entered into multiple derivatives. We have not applied hedge accounting treatment to all of our derivatives, therefore we are required to mark some of our derivatives to market through earnings on a reporting basis, which will result in non-cash adjustments to our earnings and may result in volatility in our earnings, in addition to potential cash settlements for any losses.

Commodity Price Risk

We manage our commodity price risk for electricity sales through the use of long-term power sale agreements with creditworthy counterparties. Our financial results reflect approximately 616,752 MWh and 613,249 MWh of electricity sales in the years ended December 31, 2015 and 2014, respectively, that were not subject to power sale agreements and were subject to spot-market pricing. A hypothetical increase or decrease of $2.30 per MWh and $3.59 per MWh (or an approximately 10% change) in these spot-market prices would have increased or decreased earnings by $1.4 million and $2.1 million, for the years ended December 31, 2015 and 2014, respectively.

Interest Rate Risk

As of December 31, 2015 and 2014, our long-term debt includes both fixed and variable rate debt. As long term debt is not carried at fair value on the consolidated balance sheets, changes in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of these instruments prior to their maturity. As of December 31, 2015, the estimated fair value of our debt was $1.2 billion and the carrying value of our debt was $1.2 billion. The fair value of variable interest rate long-term debt is approximated by its carrying cost. We estimate that a 1% change in market interest rates would have changed the fair value of our fixed rate debt by $32.4 million.

We are exposed to fluctuations in interest rate risk as a result of our variable rate debt and outstanding amounts due under our revolving credit facility. A hypothetical increase or decrease in interest rates by 1% would have increased or decreased interest expense related to our revolving credit facility by $1.6 million and $0.1 million for the years ended December 31, 2015 and 2014, respectively.

We may use a variety of derivative instruments, with respect to our variable rate debt, to manage our exposure to fluctuations in interest rates, including interest rate swaps and interest rate caps. As a result, our interest rate risk is limited to the unhedged portion of the variable rate debt. As of December 31, 2015, the unhedged portion of our variable rate debt was $51.2 million. A hypothetical increase or decrease in interest rates by 1% would not have a material impact to interest expense.

Interest Rate Risk and Market Price Risk Involving Convertible Senior Notes

The fair market value of our outstanding convertible senior notes, or "debentures," is subject to interest rate risk, market price risk and other factors due to the convertible feature of the debentures. The fair market value of the debentures will generally increase as interest rates fall and decrease as interest rates rise. In addition, the fair market value of the debentures will generally increase as the market price of our common stock increases and decrease as the market price of our common stock falls. The interest and market value changes affect the fair market value of the debentures, but do not impact our financial position, cash flows or results of operations due to the fixed nature of the debt obligations, except to the extent changes in the fair value of the debentures, or value of common stock, permit the holders of the debentures to convert into shares. See Note 9, Long Term Debt, in the notes to consolidated financial statements for further discussion of the convertible debt. The estimated fair value of convertible debt was $189.9 million as of

December 31, 2015. A hypothetical increase or decrease in interest rates by 1% would have resulted in a $7.2 million decrease or $7.6 million increase in the fair value.

Foreign Currency Exchange Rate Risk

Our wind power projects are located in the United States, Canada and Chile. As a result, our financial results could be significantly affected by factors such as changes in foreign currency exchange rates or weak economic conditions in the foreign markets in which we operate. When the U.S. dollar strengthens against foreign currencies, the relative value in revenue earned in the respective foreign currency decreases. When the U.S. dollar weakens against foreign currencies, the relative value in revenue earned in the respective foreign currency increases. A majority of our power sale agreements and operating expenditures are transacted in U.S. dollars, with a growing portion transacted in currencies other than the U.S. dollar, primarily the Canadian dollar. For the year ended December 31, 2015, our financial results included C$22.4 million, or $17.4 million calculated based on the monthly average exchange rate, in net income from our St. Joseph project and our equity in earnings at our South Kent, Grand and K2 projects. A hypothetical increase or decrease of 10% in exchange rates between the Canadian and U.S. dollar would have increased or decreased net earnings of St. Joseph and equity in earnings at our South Kent, Grand and K2 projects by $1.7 million and $1.2 million for the years ended December 31, 2015 and 2014, respectively.

In January 2015, we established a currency risk management program. The objective of the program is to mitigate the foreign exchange rate risk arising from transactions or cash flows that have a direct or underlying exposure in non-U.S. dollar denominated currencies in order to reduce volatility in our cash flow, which may have an adverse impact to our short-term liquidity or financial condition. For the year ended December 31, 2015, we recognized an unrealized gain on foreign currency forward contracts of $4.1 million in (loss) gain on undesignated derivatives, net in the consolidated statements of operations. We also recognized a realized gain of $1.0 million in (loss) gain on undesignated derivatives, net in the consolidated statements of operations related to foreign currency forward contracts that matured during the year ended December 31, 2015.

St. Joseph's functional currency is the Canadian dollar. As of December 31, 2015, a 10% devaluation in the Canadian dollar to the United States dollar would result in our consolidated balance sheets being negatively impacted by a $2.3 million cumulative translation adjustment in accumulated other comprehensive income (loss). The functional currency at our equity investments at South Kent, Grand and K2 is the Canadian dollar. As of December 31, 2015, a 10% devaluation in the Canadian dollar to the United States dollar would result in our unconsolidated investments being negatively impacted by a $12.4 million cumulative translation adjustment.

Item 8. Financial Statements and Supplementary Data.

The financial statements and schedules are listed in Part IV, Item 15 of this Form 10-K, beginning at page F-1, Index to Consolidated Financial Statements, and are incorporated by reference herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures pursuant to Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the "Exchange Act," as of the end of the period covered by this Form 10-K. Based on this evaluation, our chief executive officer and chief financial officer concluded that, as of December 31, 2015, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Inherent Limitations Over Internal Controls
In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.
Management's Annual Report on Internal Control over Financial Reporting
Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Management conducted an assessment of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework).
Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2015. Our independent registered public accounting firm, Ernst & Young LLP, has issued an audit report on our internal control over financial reporting, which appears below.
Change in Internal Control Over Financial Reporting
Management continuously reviews disclosure controls and procedures, and internal control over financial reporting, and accordingly may, from time to time, make changes aimed at enhancing their effectiveness to ensure that its systems evolve with its business. During 2015, enhancements included added additional resources in our technical accounting group and accounting management and increased training for our accounting staff. There were no other changes in our internal control over financial reporting during the year ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Pattern Energy Group Inc.

We have audited Pattern Energy Group Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Pattern Energy Group Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Pattern Energy Group Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Pattern Energy Group Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015 of Pattern Energy Group Inc. and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
San Francisco, California
February 29, 2016

Item 9B. Other Information.

None.

PART III

Certain information required by Part III is omitted from this Form 10-K because the registrant will file with the U.S. Securities and Exchange Commission a definitive proxy statement pursuant to Regulation 14A in connection with the solicitation of proxies for the Company’s Annual Meeting of Stockholders, or the 2016 Proxy Statement, within 120 days after the end of the fiscal year covered by this Form 10-K, and certain information included therein is incorporated herein by reference.

Item 10. Directors, Executive Officers and Corporate Governance.

The information required under this Item 10 is incorporated by reference to our 2016 Proxy Statement.

Item 11. Executive Compensation.

The information required under this Item 11 is incorporated by reference to our 2016 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required under this Item 12 is incorporated by reference to our 2016 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required under this Item 13 is incorporated by reference to our 2016 Proxy Statement.

Item 14. Principal Accounting Fees and Services.

The information required under this Item 14 is incorporated by reference to our 2016 Proxy Statement.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) Documents filed as part of this report

(1) Consolidated financial statements—Pattern Energy Group Inc.

(2) Financial Statement Schedules

(3) Exhibits

The following documents are filed or furnished as part of this Form 10-K. The Company will furnish a copy of any exhibit listed to requesting stockholders upon payment of the Company's reasonable expenses in furnishing those materials.

Exhibit No.	Description Of Exhibits
3.1	Amended and Restated Certificate of Incorporation of Pattern Energy Group Inc. (Incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1/A dated September 20, 2013 (Registration No. 333-190538)).
3.2	Amended and Restated Bylaws of Pattern Energy Group Inc. (Incorporated by reference to Exhibit 3.2 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
4.1	Form of Class A Stock Certificate (Incorporated by reference to Exhibit 3.2 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
4.2	Form of Senior Indenture (Incorporated by reference to Exhibit 4.3 to the Registrant's Registration Statement on Form S-3 dated October 8, 2014 (Registration No. 333-199217).
4.3	Form of Subordinated Indenture (Incorporated by reference to Exhibit 4.5 to the Registrant's Registration Statement on Form S-3 dated October 8, 2014 (Registration No. 333-199217).
4.4	Indenture, dated July 28, 2015, among Pattern Energy Group Inc., as issuer, Pattern US Finance Company LLC, as subsidiary guarantor, and Deutsche Bank Trust Company Americas, as trustee, related to 4.00% Convertible Senior Notes due 2020 (Incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K dated July 28, 2015).
10.1	Amended and Restated Credit and Guaranty Agreement, among Pattern US Finance Company LLC, Pattern Canada Finance Company ULC, as borrowers, certain subsidiaries of the borrowers, the lenders party thereto from time to time, Royal Bank of Canada, as Swingline Lender, Administrative Agent and Collateral Agent, Bank of Montreal, as Syndication Agent, and Morgan Stanley Senior Funding, Inc., as Documentation Agent, dated as of December 17, 2014(the "Amended and Restated Credit and Guaranty Agreement) (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated December 17, 2014).
10.2	Amendment No. 2 dated as of September 28, 2015 to the Amended and Restated Credit and Guaranty Agreement (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated September 28, 2015).
10.3	Amendment No. 3 dated as of November 20, 2015 to the Amended and Restated Credit and Guaranty Agreement (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated November 17, 2015).
10.4	Pattern Energy Group Inc. 2013 Equity Incentive Award Plan (Incorporated by reference to Exhibit 10.2 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).

10.5	Form of Pattern Energy Group Inc. 2013 Incentive Bonus Plan. (Incorporated by reference to Exhibit 10.3 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
10.6	Form of Stock Option Agreement under 2013 Equity Incentive Award Plan. (Incorporated by reference to Exhibit 10.4 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
10.7	Form of Restricted Stock Agreement under 2013 Equity Incentive Award Plan. (Incorporated by reference to Exhibit 10.5 to the Registrant's Registration Statement on Form S-1/A dated September 20, 2013 (Registration No. 333-190538)).
10.8	Form of Restricted Stock Unit Agreement under 2013 Equity Incentive Award Plan. (Incorporated by reference to Exhibit 10.6 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
10.9	Form of Deferred Restricted Stock Unit Agreement under 2013 Equity Incentive Award Plan. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K dated December 17, 2014).
10.10	Form of Indemnification Agreement between the Registrant and each of its Executive Officers and Directors. (Incorporated by reference to Exhibit 10.7 to the Registrant's Registration Statement on Form S-1/A dated September 3, 2013 (Registration No. 333-190538)).
10.11	Registration Rights Agreement between the Company and Pattern Energy Group LP, dated as of October 2, 2013. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated September 26, 2013).
10.12	Contribution Agreement among the Company, Pattern Renewables LP, Pattern Energy Group LP, and Pattern Renewable Holdings Canada ULC, dated as of October 2, 2013. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K dated September 26, 2013).
10.13	Purchase Rights Agreement among the Company, Pattern Energy Group LP, Pattern Energy Group Holdings LP and Pattern Energy GP LLC, dated as of October 2, 2013. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K dated September 26, 2013).
10.14	Bilateral Management Services Agreement between the Company and Pattern Energy Group LP, dated as of October 2, 2013. (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K dated September 26, 2013).

Exhibit No.	Description Of Exhibits
10.15	First Amendment to Bilateral Management Services Agreement between the Company and Pattern Energy Group LP dated July 3, 2015 (Incorporated by reference to the Exhibit 10.1 to the Company's Current Report on Form 8-K dated July 3, 2015).
10.16	Non-Competition Agreement between the Company and Pattern Energy Group LP, dated October 2, 2013. (Incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K dated September 26, 2013).
10.17	Shareholder Approval Rights Agreement between the Company and Pattern Energy Group LP, dated as of October 2, 2013. (Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K dated September 26, 2013).
10.18	Purchase and Sale Agreement, dated as of December 20, 2013, by and between Pattern Canada Operations Holdings ULC and Pattern Energy Group LP (Grand PSA) . (Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K dated December 20, 2013).
10.19	Purchase and Sale Agreement, dated as of December 20, 2013, by and among Pattern Energy Group Inc., Panhandle B Holdco 2 LLC and Pattern Energy Group LP (PH2 PSA) (Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K dated December 20, 2013).
10.20	Management, Operation and Maintenance Agreement, dated as of December 20, 2013, by and between Pattern Panhandle Wind 2 LLC and Pattern Operators LP (PH2 MOMA) (Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K dated December 20, 2013).
10.21	Project Administration Agreement, dated as of December 20, 2013, by and between Pattern Panhandle Wind 2 LLC and Pattern Operators LP (PH2 PAA) (Incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K dated December 20, 2013).
10.22	Purchase and Sale Agreement, dated as of May 1, 2014, by and among Pattern Energy Group Inc., Pattern Renewables LP and Pattern Energy Group LP (PH1 PSA) (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K dated May 2, 2014).
10.23	Purchase and Sale Agreement by and among Pattern Energy Group Inc., as Purchaser, Pattern Renewables LP, as Seller, and (solely for purposes of Section 7.1) Pattern Energy Group LP, as Guarantor, dated as of December 19, 2014 (Logan's Gap PSA) (Incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K dated December 19, 2014).
10.24	Purchase and Sale Agreement, by and between Pattern Energy Group Inc., Pattern Renewables Development Company LLC, and (as guarantor for certain obligations) Pattern Energy Group LP dated April 29, 2015 (Amazon Wind Farm Fowler Ridge PSA) (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated April 29, 2015).
10.25	Purchase and Sale Agreement, by and between Wind Capital Group, LLC, Lincoln County Wind Project Finco, LLC and Pattern Energy Group Inc., dated April 1, 2015 (Incorporated by

	reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated May 15, 2015).
10.26	Purchase and Sale Agreement between Pattern Canada Finance Company ULC and Pattern Energy Group LP dated April 4, 2015 (K2 PSA) (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated June 17, 2015).
10.27	Purchase Agreement between Pattern Gulf Wind Equity 2 LLC, as seller, and Pattern Gulf Wind Equity LLC, as buyer, dated July 20, 2015 (Incorporated by reference to the Exhibit 10.1 to the Company's Current Report on Form 8-K dated July 20, 2015).
10.28	Employment Agreement between Pattern Energy Group Inc. and Michael M. Garland dated October 2, 2013 (Incorporated by reference to Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2013).
10.29	Employment Agreement between Pattern Energy Group Inc. and Hunter H. Armistead dated October 2, 2013 (Incorporated by reference to Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2013).
10.30	Employment Agreement between Pattern Energy Group Inc. and Daniel M. Elkort dated October 2, 2013 (Incorporated by reference to Exhibit 10.21 to the Registrant's Annual Report on Form 10-K for the fiscal year ended December 31, 2013).
10.31	Employment Agreement between Pattern Energy Group Inc. and Esben Pedersen dated October 2, 2013 (Incorporated by reference to Exhibit 10.16 to the Registrant's Registration Statement on Form S-1 dated April 25, 2014 (Registration No. 333-195488)).
10.32	Employment Agreement between Pattern Energy Group Inc. and Michael J. Lyon dated October 2, 2013 (Incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q dated May 7, 2015).
10.33	Assignment and Assumption of Lease and Consent of Landlord Agreement, effective as of January 1, 2016, by and between Pattern Energy Group LP, Pattern Energy Group Inc., and AMB Pier One, LLC (Incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K dated January 25, 2016).

Exhibit No.	Description Of Exhibits
21.1**	Subsidiaries of the Registrant
23.1**	Consent of Independent Registered Public Accounting Firm
23.2**	Consent of PricewaterhouseCoopers LLP
24.1	Powers of Attorney (included in the signature pages to this filing).
31.1**	Certifications of the Chief Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2**	Certifications of the Chief Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32*	Certifications of the Company's Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Amendment No. 1 dated as of June 12, 2015 to the Amended and Restated Credit and Guaranty Agreement (Incorporated by reference to Exhibit 99.1 to the Company's Quarterly Report on Form 10-Q dated November 5, 2015).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* These certifications accompany this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed "filed" by the Company for purposes of Section 18 of the Exchange Act.

** Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date:	February 29, 2016	Pattern Energy Group Inc.	
		By	/s/ Michael M. Garland
			Michael M. Garland
			President and Chief Executive Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Dyann Blaine and Michael Lyon, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and re-substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming that all said attorneys-in-fact and agents, or any of them or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ MICHAEL M. GARLAND Michael M. Garland	President, Chief Executive Officer and Director of Pattern Energy Group Inc. (Principal Executive Officer)	February 29, 2016
/s/ ALAN R. BATKIN Alan R. Batkin	Director and Chairman of Pattern Energy Group Inc.	February 29, 2016
/s/ PATRICIA S. BELLINGER Patricia S. Bellinger	Director of Pattern Energy Group Inc.	February 29, 2016
/s/ THE LORD BROWNE OF MADINGLEY The Lord Browne of Madingley	Director of Pattern Energy Group Inc.	February 29, 2016
/s/ DOUGLAS G. HALL Douglas G. Hall	Director of Pattern Energy Group Inc.	February 29, 2016
/s/ MICHAEL B. HOFFMAN Michael B. Hoffman	Director of Pattern Energy Group Inc.	February 29, 2016
/s/ PATRICIA M. NEWSON Patricia M. Newson	Director of Pattern Energy Group Inc.	February 29, 2016
/s/ MICHAEL J. LYON Michael J. Lyon	Chief Financial Officer of Pattern Energy Group Inc. (Principal Financial Officer)	February 29, 2016
/s/ ERIC S. LILLYBECK Eric S. Lillybeck	Senior Vice President, Fiscal and Administrative Services of Pattern Energy Group Inc. (Principal Accounting Officer)	February 29, 2016

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm
Board of Directors and Stockholders
Pattern Energy Group Inc.

We have audited the accompanying consolidated balance sheets of Pattern Energy Group Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement Schedule I listed in the Index at Item 15(a)(2). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. We did not audit the financial statements of South Kent Wind LP, Grand Renewable Wind LP partnerships in which the Company has a 50% and 45% interest, respectively. In the consolidated financial statements, the Company's investment in South Kent Wind LP and Grand Renewable Wind LP is stated at $11,920,000 and $29,079,000 at December 31, 2015 and 2014, respectively, and the Company's equity in the net earnings (loss) of South Kent Wind LP and Grand Renewable Wind LP is stated at $12,233,000 and ($24,775,000) for the years ended December 31, 2015 and 2014, respectively. The statements for South Kent Wind LP and Grand Renewable Wind LP were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for South Kent Wind LP and Grand Renewable Wind LP, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pattern Energy Group Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement Schedule I, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pattern Energy Group Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
San Francisco, California
February 29, 2016

Pattern Energy Group Inc.
Consolidated Balance Sheets
(In thousands of U.S. Dollars, except share data)

	December 31, 2015	2014
Assets		
Current assets:		
Cash and cash equivalents	$94,808	$101,656
Restricted cash	14,609	7,945
Trade receivables	45,292	35,759
Related party receivable	734	671
Reimbursable interconnection costs	38	2,532
Derivative assets, current	24,338	18,506
Current net deferred tax assets	—	318
Prepaid expenses	14,498	15,275
Other current assets	6,891	12,679
Deferred financing costs, current, net of accumulated amortization of $5,192 and $3,493 as of December 31, 2015 and 2014, respectively	2,121	1,747
Total current assets	203,329	197,088
Restricted cash	36,875	39,745
Turbine advances	—	79,637
Construction in progress	—	26,195
Property, plant and equipment, net of accumulated depreciation of $409,161 and $278,291 as of December 31, 2015 and 2014, respectively	3,294,620	2,350,856
Unconsolidated investments	116,473	29,079
Derivative assets	44,014	49,369
Deferred financing costs	4,572	5,166
Net deferred tax assets	6,804	5,474
Finite-lived intangible assets, net of accumulated amortization of $4,357 and $154 as of December 31, 2015 and 2014, respectively	97,722	1,257
Other assets	25,183	11,421
Total assets	$3,829,592	$2,795,287

(Continued)

Pattern Energy Group Inc.
Consolidated Balance Sheets
(In thousands of U.S. Dollars, except share data)

	December 31, 2015	2014
Liabilities and equity		
Current liabilities:		
Accounts payable and other accrued liabilities	$42,776	$24,793
Accrued construction costs	23,565	20,132
Related party payable	1,646	5,757
Accrued interest	9,035	3,634
Dividends payable	28,022	15,734
Derivative liabilities, current	14,343	16,307
Revolving credit facility	355,000	50,000
Current portion of long-term debt, net of financing costs of $3,671 and $11,868 as of December 31, 2015 and 2014, respectively	44,144	109,693
Current net deferred tax liabilities	—	149
Other current liabilities	2,156	4,000
Total current liabilities	520,687	250,199
Long-term debt, net of financing costs of $22,632 and $24,887 as of December 31, 2015 and 2014, respectively	1,174,380	1,304,165
Convertible senior notes, net of financing costs of $5,014 and $0 as of December 31, 2015 and 2014, respectively	197,362	—
Derivative liabilities	28,659	17,467
Net deferred tax liabilities	22,183	20,418
Finite-lived intangible liability, net of accumulated amortization of $2,168 and $0 as of December 31, 2015 and 2014, respectively	58,132	—
Other long-term liabilities	52,427	38,304
Total liabilities	2,053,830	1,630,553
Commitments and contingencies (Note 18)		
Equity:		
Class A common stock, $0.01 par value per share: 500,000,000 shares authorized; 74,644,141 and 62,062,841 shares outstanding as of December 31, 2015 and 2014, respectively	747	621
Additional paid-in capital	982,814	723,938
Accumulated loss	(77,159)	(44,626)
Accumulated other comprehensive loss	(73,325)	(45,068)
Treasury stock, at cost; 65,301 and 25,465 shares of Class A common stock as of December 31, 2015 and 2014, respectively	(1,577)	(717)
Total equity before noncontrolling interest	831,500	634,148
Noncontrolling interest	944,262	530,586
Total equity	1,775,762	1,164,734
Total liabilities and equity	$3,829,592	$2,795,287

(Concluded)
See accompanying notes to consolidated financial statements.

Pattern Energy Group Inc.
Consolidated Statements of Operations
(In thousands of U.S. Dollars, except share data)

	Year ended December 31, 2015	2014	2013
Revenue:			
Electricity sales	$324,275	$254,669	$178,796
Related party revenue	3,640	3,317	911
Other revenue	1,916	7,507	21,866
Total revenue	329,831	265,493	201,573
Cost of revenue:			
Project expense	114,619	77,775	57,677
Depreciation, amortization and accretion	143,376	104,417	83,180
Total cost of revenue	257,995	182,192	140,857
Gross profit	71,836	83,301	60,716
Operating expenses:			
General and administrative	29,807	22,533	4,819
Related party general and administrative	7,589	5,787	8,169
Total operating expenses	37,396	28,320	12,988
Operating income	34,440	54,981	47,728
Other (expense) income:			
Interest expense	(77,907)	(67,694)	(63,614)
(Loss) gain on undesignated derivatives, net	(5,490)	(15,743)	13,502
Realized loss on designated derivatives	(11,221)	—	—
Equity in earnings (losses) in unconsolidated investments	16,119	(25,295)	7,846
Related party income	2,665	2,612	665
Early extinguishment of debt	(4,941)	—	—
Net (loss) gain on transactions	(3,400)	13,843	5,995
Other (expense) income, net	(929)	433	2,496
Total other expense	(85,104)	(91,844)	(33,110)
Net (loss) income before income tax	(50,664)	(36,863)	14,618
Tax provision	4,943	3,136	4,546
Net (loss) income	(55,607)	(39,999)	10,072
Net loss attributable to noncontrolling interest	(23,074)	(8,709)	(6,887)
Net (loss) income attributable to Pattern Energy	$(32,533)	$(31,290)	$16,959
Loss per share information:			
Net (loss) income attributable to Pattern Energy	(32,533)	(31,290)	16,959
Less: Net income attributable to Pattern Energy prior to the initial public offering on October 2, 2013			(30,295)
Net loss attributable to Pattern Energy subsequent to the initial public offering			$(13,336)
Dividends declared on Class A common shares	(102,861)	(56,976)	(11,103)
Deemed dividends on Class B common shares	—	(21,901)	—
Earnings allocated to participating securities	(32)	—	—
Undistributed loss attributable to common stockholders	$(135,426)	$(110,167)	$(24,439)
Weighted average number of shares:			

Class A common stock - Basic and diluted	70,535,568	42,361,959	35,448,056
Class B common stock - Basic and diluted	—	15,555,000	15,555,000

Pattern Energy Group Inc.
Consolidated Statements of Operations
(In thousands of U.S. Dollars, except share data)

	Year ended December 31,		
	2015	2014	2013
Loss per share			
Class A common stock:			
Basic and diluted loss per share	$(0.46)	$(0.56)	$(0.17)
Class B common stock:			
Basic and diluted loss per share	$—	$(0.49)	$(0.48)
Dividends declared per Class A common share	$1.43	$1.30	$0.31
Deemed dividends per Class B common share	$—	$1.41	$—

See accompanying notes to consolidated financial statements.

Pattern Energy Group Inc.
Consolidated Statements of Comprehensive (Loss) Income
(In thousands of U.S. Dollars)

	Year ended December 31,		
	2015	2014	2013
Net (loss) income	$(55,607)	$(39,999)	$10,072
Other comprehensive (loss) income:			
Foreign currency translation, net of zero tax impact	(28,947)	(10,875)	(8,309)
Derivative activity:			
Effective portion of change in fair market value of derivatives, net of tax benefit of $1,860, $1,138 and $0, respectively	(16,163)	(33,444)	24,932
Reclassifications to net loss due to termination/de-designation of interest rate derivatives, net of zero tax impact	17,139	—	—
Reclassifications to net loss, net of tax impact of $670, $404 and $0, respectively	12,234	13,774	11,943
Total change in effective portion of change in fair market value of derivatives	13,210	(19,670)	36,875
Proportionate share of equity investee's derivative activity:			
Effective portion of change in fair market value of derivatives, net of tax benefit (provision) of $2,394, $1,855 and ($615), respectively	(6,640)	(5,991)	2,473
Reclassifications to net loss, net of tax impact of $870, $0 and $0, respectively	2,412	—	—
Total change in effective portion of change in fair market value of derivatives	(4,228)	(5,991)	2,473
Total other comprehensive (loss) income, net of tax	(19,965)	(36,536)	31,039
Comprehensive (loss) income	(75,572)	(76,535)	41,111
Less comprehensive (loss) income attributable to noncontrolling interest:			
Net loss attributable to noncontrolling interest	(23,074)	(8,709)	(6,887)
Derivative activity:			
Effective portion of change in fair market value of derivatives, net of tax benefit of $185, $341 and $0, respectively	(1,740)	(3,422)	3,184
Reclassifications to net loss, net of tax impact of $201, $121 and 0, respectively	2,088	3,601	1,904
Total change in effective portion of change in fair market value of derivatives	348	179	5,088
Comprehensive loss attributable to noncontrolling interest	(22,726)	(8,530)	(1,799)
Comprehensive (loss) income attributable to Pattern Energy	$(52,846)	$(68,005)	$42,910

See accompanying notes to consolidated financial statements.

Pattern Energy Group Inc.
Consolidated Statement of Stockholders' Equity
(In thousands of U.S. Dollars, except share data)

	Class A Common Stock		Class B Common Stock		Treasury Stock		Additional Paid-in Capital	Capital	Accumulated Income (Loss)	Accumulated Other Comprehensive Loss	Total	Noncor Interest
	Shares	Amount	Shares	Amount	Shares	Amount						
Balances at December 31, 2012	100	$—	—	$—	—	$—	$1	$545,471	$2,903	$(34,264)	$514,111	$75,30
Contribution	—	—	—	—	—	—	—	32,677	—	—	32,677	—
Distribution	—	—	—	—	—	—	—	(104,634)	—	—	(104,634)	(1,426
Additional paid-in capital	—	—	—	—	—	—	2	—	—	—	2	—
Net income (loss)	—	—	—	—	—	—	—	—	30,295	—	30,295	(690
Other comprehensive income, net of tax	—	—	—	—	—	—	—	—	—	20,633	20,633	3,559
Balances at October 1, 2013	100	—	—	—	—	—	3	473,514	33,198	(13,631)	493,084	76,744
Interest in Gulf Wind retained by Pattern Development	—	—	—	—	—	—	—	(18,332)	(13,122)	2,870	(28,584)	28,584
Assumption of liabilities related to Contribution Transactions	—	—	—	—	—	—	—	(4,207)	—	—	(4,207)	—
Issuance of common stock for Contribution Transactions	19,445,000	194	15,555,000	156	—	—	470,701	(450,975)	(20,076)	—	—	—
Deemed distribution for Contribution Transactions	—	—	—	—	—	—	(232,640)	—	—	—	(232,640)	—
Issuance of Class A common stock related to the	16,000,000	160	—	—	—	—	316,882	—	—	—	317,042	—

initial public offering, net of issuance costs												
Issuance of Class A restricted common stock	83,183	1	—	—	—	—	155	—	—	—	156	—
Issuance of Class A common stock	3,437	—	—	—	—	—	93	—	—	—	93	—
Repurchase of shares for employee tax withholding	—	—	—	—	(934)	(24)	—	—	—	—	(24)	—
Stock-based compensation	—	—	—	—	—	—	263	—	—	—	263	—
Dividends declared on Class A common stock	—	—	—	—	—	—	(11,103)	—	—	—	(11,103)	—
Acquisition from Pattern Development	—	—	—	—	—	—	(54,942)	—	—	(2,910)	(57,852)	—
Distribution to noncontrolling interest	—	—	—	—	—	—	—	—	—	—	—	(866
Net loss	—	—	—	—	—	—	—	—	(13,336)	—	(13,336)	(6,197
Other comprehensive income, net of tax	—	—	—	—	—	—	—	—	—	5,318	5,318	1,529
Balances at December 31, 2013	35,531,720	355	15,555,000	156	(934)	(24)	489,412	—	(13,336)	(8,353)	468,210	99,794
Issuance of Class A common stock related to the public offering, net of issuance costs	10,810,810	108	—	—	—	—	286,785	—	—	—	286,893	—
Issuance of Class A restricted common stock	175,915	2	—	—	—	—	3,494	—	—	—	3,496	—
Issuance of Class A common stock upon exercise of stock options	14,861	—	—	—	—	—	327	—	—	—	327	—
	—	—	—	—	(24,531)	(693)	—	—	—	—	(693)	—

Repurchase of shares for employee tax withholding												
Conversion of Class B common stock to Class A common stock	15,555,000	156	(15,555,000)	(156)	—	—	—	—	—	—	—	—
Stock-based compensation	—	—	—	—	—	—	610	—	—	—	610	—
Refund of issuance costs related to the initial public offering	—	—	—	—	—	—	286	—	—	—	286	—
Dividends declared on Class A common stock	—	—	—	—	—	—	(56,976)	—	—	—	(56,976)	—
Recognition of beneficial conversion feature on Class B convertible common stock	—	—	—	—	—	—	(21,901)	—	—	—	(21,901)	—
Adjustment to paid-in capital for beneficial conversion feature recognition	—	—	—	—	—	—	21,901	—	—	—	21,901	—
Accretion of the Class B beneficial conversion feature	—	—	—	—	—	—	21,901	—	—	—	21,901	—
Deemed dividends on Class B convertible common stock	—	—	—	—	—	—	(21,901)	—	—	—	(21,901)	—
Contribution from noncontrolling interests	—	—	—	—	—	—	—	—	—	—	—	406,163
Fair value of noncontrolling interest in El Arrayán	—	—	—	—	—	—	—	—	—	—	—	35,259

Distribution to noncontrolling interests	—	—	—	—	—	—	—	—	—	—	—	(2,100
Net loss	—	—	—	—	—	—	—	—	(31,290)		(31,290)	(8,709
Other comprehensive (loss) income, net of tax	—	—	—	—	—	—	—	—	—	(36,715)	(36,715)	179
Balances at December 31, 2014	62,088,306	621	—	—	(25,465)	(717)	723,938	—	(44,626)	(45,068)	634,148	530,586
Issuance of Class A common stock related to the public offerings, net of issuance costs	12,435,000	124	—	—	—	—	316,828	—	—	—	316,952	—
Issuance of Class A common stock under equity incentive award plan	186,136	2	—	—	—	—	(2)	—	—	—	—	—
Repurchase of shares for employee tax withholding	—	—	—	—	(39,836)	(860)	—	—	—	—	(860)	—
Stock-based compensation	—	—	—	—	—	—	4,462	—	—	—	4,462	—
Dividends declared on Class A common stock	—	—	—	—	—	—	(102,893)	—	—	—	(102,893)	—
Dividend equivalents declared upon vesting of deferred restricted stock units	—	—	—	—	—	—	23	—	—	—	23	—
Acquisition of Post Rock	—	—	—	—	—	—	—	—	—	—	—	205,100
Conversion option of convertible senior notes, net of issuance costs	—	—	—	—	—	—	23,743	—	—	—	23,743	—
	—	—	—	—	—	—	16,715	—	—	(7,944)	8,771	(95,047

Buyout of noncontrolling interests												
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	—	—	334,23
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	—	—	(7,882
Net loss	—	—	—	—	—	—	—	—	(32,533)	—	(32,533)	(23,074
Other comprehensive (loss) income, net of tax	—	—	—	—	—	—	—	—	—	(20,313)	(20,313)	348
Balances at December 31, 2015	74,709,442	$747	$—	$—	(65,301)	$(1,577)	$982,814	$—	$(77,159)	$(73,325)	$831,500	$944,2

See accompanying notes to consolidated financial statements.

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Pattern Energy Group Inc.
Consolidated Statements of Cash Flows
(In thousands of U.S. Dollars)

	Year ended December 31,		
	2015	2014	2013
Operating activities			
Net loss	$(55,607)	$(39,999)	$10,072
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, amortization and accretion	143,376	104,417	83,180
Impairment loss	398	—	—
Amortization of financing costs	7,435	6,309	6,816
Loss (gain) on derivatives, net	2,219	15,546	(4,329)
Stock-based compensation	4,462	4,105	511
Net gain on transactions	—	(16,526)	(5,995)
Deferred taxes	4,494	2,948	4,546
Equity in (earnings) losses in unconsolidated investments	(16,180)	25,295	(7,846)
Unrealized loss on exchange rate changes	823	—	—
Amortization of power purchase agreements, net	1,946	—	—
Amortization of debt discount/premium, net	1,660	—	—
Realized loss on designated derivatives	11,221	—	—
Early extinguishment of debt	4,722	—	—
Changes in operating assets and liabilities:			
Trade receivables	(2,254)	(8,255)	(8,721)
Reimbursable interconnection receivable	—	—	(11)
Prepaid expenses	1,272	(4,100)	(7,021)
Other current assets	(2,929)	17,016	4,323
Other assets (non-current)	(2,336)	(649)	(566)
Accounts payable and other accrued liabilities	4,716	3,667	3,036
Related party receivable/payable	711	(942)	190
Accrued interest payable	4,489	1,377	(33)
Contingent liabilities	515	—	—
Long-term liabilities	2,696	239	—
Increase in restricted cash	(2,120)	—	—
Decrease in restricted cash	2,120	—	—
Net cash provided by operating activities	117,849	110,448	78,152

Pattern Energy Group Inc.
Consolidated Statements of Cash Flows
(In thousands of U.S. Dollars)

	Year ended December 31,		
	2015	2014	2013
Investing activities			
Receipt of ITC Cash Grant	$—	$—	$173,446
Cash paid for acquisitions, net of cash acquired	(433,792)	(306,584)	(30,070)
Proceeds from sale of investments	—	—	14,254
Decrease in restricted cash	62,583	46,700	66,517
Increase in restricted cash	(57,332)	(40,790)	(80,569)
Capital expenditures	(380,458)	(119,506)	(123,517)
Deferred development costs	—	—	(528)
Distribution from unconsolidated investments	38,240	22,019	10,463
Contribution to unconsolidated investments	(3)	(2,651)	(9,678)
Reimbursable interconnection receivable	2,494	3,892	49,715
Other assets	3,065	17,540	2,358
Net cash (used in) provided by investing activities	(765,203)	(379,380)	72,391

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Pattern Energy Group Inc.
Consolidated Statements of Cash Flows
(In thousands of U.S. Dollars)

	Year ended December 31, 2015	2014	2013
Financing activities			
Proceeds from public offering, net of issuance costs	$317,432	$286,757	$317,926
Proceeds from issuance of convertible senior notes, net of issuance costs	218,929	—	—
Proceeds from exercise of stock options	—	327	—
Repurchase of shares for employee tax withholding	(860)	(693)	(24)
Dividends paid	(90,582)	(52,344)	—
Payment for acquisitions from Pattern Development	—	—	(49,430)
Capital distributions - Contribution Transactions	—	—	(232,640)
Capital contributions - Pattern Development	—	—	32,679
Capital distributions - Pattern Development	—	—	(98,886)
Payment for deferred equity issuance costs	—	(550)	—
Buyout of noncontrolling interests	(121,224)	—	—
Capital contributions - noncontrolling interest	336,043	200,805	—
Capital distributions - noncontrolling interest	(7,882)	(2,100)	(2,292)
Decrease in restricted cash	56,218	19,627	122,689
Increase in restricted cash	(54,592)	(17,903)	(127,369)
Refund of deposit for letters of credit	3,425	(3,422)	—
Payment for deferred financing costs	(13,667)	(11,856)	(294)
Proceeds from revolving credit facility	405,000	50,000	56,000
Repayment of revolving credit facility	(100,000)	—	(56,000)
Proceeds from construction loans	329,070	59,778	—
Proceeds from long-term debt	164,973	—	138,620
Repayment of long-term debt	(785,923)	(259,437)	(164,380)
Payment for interest rate derivatives	(11,061)	—	—
Net cash provided by financing activities	645,299	268,989	(63,401)
Effect of exchange rate changes on cash and cash equivalents	(4,793)	(1,970)	(1,147)
Net change in cash and cash equivalents	(6,848)	(1,913)	85,995
Cash and cash equivalents at beginning of period	101,656	103,569	17,574
Cash and cash equivalents at end of period	$94,808	$101,656	$103,569
Supplemental disclosures			
Cash payments for income taxes	$342	$131	$—
Cash payments for interest expense, net of capitalized interest	62,607	53,776	53,295
Acquired property, plant and equipment from acquisitions	581,834	1,013,365	—
Equity issuance costs paid in prior period related to current period offerings	(433)	—	(884)
Schedule of non-cash activities			
Change in fair value of designated interest rate swaps	$13,210	$(22,847)	$36,875
Change in property, plant and equipment	15,695	(47,908)	(109,281)
Non-cash deemed dividends on Class B convertible common stock	—	21,901	—
	16,715	—	—

Non-cash increase in additional paid-in capital from buyout of noncontrolling interests			
Amortization of deferred financing costs—included as construction in progress	—	343	175
Transfer of capitalized assets to South Kent joint venture	—	—	49,275
Non-cash distribution to Pattern Development	—	—	(5,748)
Assumption of contingent liability related to Contribution Transactions	—	—	(4,207)
Assumption of contingent liability upon acquisition of Logan's Gap	—	(4,000)	—

See accompanying notes to consolidated financial statements.

Pattern Energy Group Inc.
Notes to Consolidated Financial Statements
1. Organization
Pattern Energy Group Inc. ("Pattern Energy" or the "Company") was organized in the state of Delaware on October 2, 2012. Pattern Energy issued 100 shares on October 17, 2012 to Pattern Renewables LP, a 100% owned subsidiary of Pattern Energy Group LP ("Pattern Development"). On September 24, 2013, Pattern Energy’s charter was amended, and the number of shares that Pattern Energy is authorized to issue was increased to 620,000,000 total shares; 500,000,000 of which are designated Class A common stock, 20,000,000 of which were designated Class B common stock, and 100,000,000 of which are designated Preferred Stock.
On October 2, 2013, concurrent with the initial public offering, the Company issued to Pattern Development 19,445,000 shares of Class A common stock, representing 63% of the Company's Class A common stock outstanding at the time, and 15,555,000 shares of Class B common stock. On December 31, 2014, the Company’s outstanding Class B common stock was converted into Class A common stock on a one-for-one basis. As a result, the shares of Class B common stock were retired and the Company is no longer authorized to issue shares of Class B common stock.
On May 14, 2014, the Company completed an underwritten public offering of its Class A common stock resulting in a reduction of Pattern Development’s interest in the Company from approximately 63% to 35%. Consequently, the Company is no longer subject to Accounting Standards Codification ("ASC") 805-50-30-5, Transactions between Entities under Common Control. All transactions with Pattern Development after May 14, 2014 are recognized at fair value on the measurement date in accordance with the ASC 805, Business Combinations. On February 9, 2015, the Company completed an underwritten public offering of its Class A common stock, resulting in a further reduction of Pattern Development’s interest in the Company from 35% to 25% causing it to no longer be entitled to certain approval rights pursuant to the Shareholder Approval Rights Agreement dated October 2, 2013. Refer to Note 15, Stockholders' Equity - Common Stock, for additional information on equity transactions that occurred during the year.
Pattern Energy is an independent energy generation company focused on constructing, owning and operating energy projects with long-term energy sales contracts located in the United States, Canada and Chile. The Company consists of the consolidated operations of certain entities and assets contributed by, or purchased principally from, Pattern Development, except for purchases of Lost Creek, Post Rock and certain additional interests in El Arrayán (each as defined below, which were purchased from third-parties). Each of the Company's wind projects are consolidated into the Company's subsidiaries which are organized by geographic location: Pattern US Operations Holdings LLC, Pattern Canada Operations Holdings ULC and Pattern Chile Holdings LLC. The Company owns 100% of Hatchet Ridge Wind, LLC ("Hatchet Ridge"), St. Joseph Windfarm Inc. ("St. Joseph"), Spring Valley Wind LLC ("Spring Valley"), Pattern Santa Isabel LLC ("Santa Isabel"), Ocotillo Express LLC ("Ocotillo"), Pattern Gulf Wind LLC ("Gulf Wind") and Lost Creek Wind, LLC ("Lost Creek") and owns a controlling interest in Pattern Panhandle Wind LLC ("Panhandle 1"), Pattern Panhandle Wind 2 LLC ("Panhandle 2"), Post Rock Wind Power Project, LLC ("Post Rock"), Logan's Gap Wind LLC ("Logan's Gap") and Fowler Ridge IV Wind Farm LLC ("Amazon Wind Farm Fowler Ridge"), all of which are consolidated into Pattern US Operations Holdings LLC. The Company also owns a controlling interest in Parque Eólico El Arrayán SpA ("El Arrayán") which is consolidated into Pattern Chile Holdings LLC, and noncontrolling interests in South Kent Wind LP ("South Kent"), Grand Renewable Wind LP ("Grand") and K2 Wind Ontario Limited Partnership ("K2"), which are accounted for as equity method investments in Pattern Canada Operations Holdings ULC. The principal business objective of the Company is to produce stable and sustainable cash flows through the generation and sale of energy and to selectively grow our project portfolio.
Pattern Energy was formed by Pattern Development for the purpose of an initial public offering ("IPO"). For periods prior to October 2, 2013, Pattern Energy was a shell company, with expenses of less than $10,000 for 2013. In accordance with ASC 805-50-30-6, Transactions Between Entities Under Common Control, the historical financial statements of Pattern Energy’s predecessor, which consist of the combined financial statements of a combination of entities and assets contributed by Pattern Development to Pattern Energy, are consolidated with Pattern Energy from the beginning of the earliest period presented.

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The accompanying consolidated financial statements have been prepared in accordance with the accounting principles generally accepted in the United States ("U.S. GAAP"). They include the results of wholly-owned and partially-owned subsidiaries in which the Company has a controlling interest with all significant intercompany accounts and transactions eliminated.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates, and such differences may be material to the consolidated financial statements.

Change in Depreciable Lives of Property, Plant and Equipment

The Company periodically reviews the estimated economic useful lives of its fixed assets. In 2015, based on technical review of various wind farm characteristics, the expected economic useful lives of certain wind farms were longer than the estimated economic useful lives used for depreciation purposes in the Company’s financial statements. As a result, effective January 1, 2015, the Company changed its estimate of the economic useful lives of wind farms for which construction began after 2011, from 20 to 25 years. All other wind farms continue to depreciate over an estimated economic useful life of 20 years. For the year ended December 31, 2015, the effect of this change reduced depreciation expense by $14.7 million, decreased net loss by $13.9 million, net of tax, and decreased Class A basic and diluted loss per share by $0.09.

Reclassification

Certain prior period balances have been reclassified to conform to the current period presentation in the Company’s consolidated financial statements and the accompanying notes.

The Company has also revised its consolidated statements of comprehensive income (loss) for the years December 31, 2014 and 2013 to correct an immaterial classification error. The consolidated statements of comprehensive income (loss) for the years ended December 31, 2014 and 2013 have been corrected to reflect the reclassification of approximately $27.5 million and $23.9 million, respectively, between the effective portion of change in fair market value of derivatives and reclassification to net loss attributable to Pattern Energy. The consolidated statements of comprehensive income (loss) for the years ended December 31, 2014 and 2013 have also been corrected to reflect the reclassification of approximately $7.2 million and $3.8 million, respectively, between the effective portion of change in fair market value of derivatives and reclassification to net loss for noncontrolling interest. These revisions had no impact on comprehensive loss or comprehensive loss attributable to noncontrolling interest. Changes in accumulated other comprehensive loss by component, as disclosed in Note 12, Accumulated Other Comprehensive Loss, have also been corrected to reflect this immaterial error correction.

Variable Interest Entities

ASC 810, Consolidation of Variable Interest Entities, defines the criteria for determining the existence of Variable Interest Entities ("VIEs") and provides guidance for consolidation. The Company consolidates VIEs where the Company is the primary beneficiary. The primary beneficiary of a VIE is the party that has the power to direct the activities that most significantly impact the performance of the entity and the obligation to absorb losses or the right to receive benefits that could potentially be significant to the entity. Investments or joint ventures in which the Company does not have a majority ownership interest and are not VIEs for which the Company is considered the primary beneficiary are accounted for using the equity method. These amounts are included in unconsolidated investments in the consolidated balance sheets.

Acquisitions

Business Combinations

When the Company acquires a controlling interest, the purchase is accounted for using the acquisition method, and the fair value of purchase consideration is allocated to the tangible and intangible assets acquired and liabilities assumed, including contingent consideration, based on their estimated fair values. The excess, if any, of the fair value of purchase consideration over the fair values of these identifiable assets and liabilities is recorded as goodwill. Conversely, the excess, if any, of the net fair values of identifiable assets and liabilities over the fair value of purchase consideration is recorded as gain. Such valuations require management to make significant estimates and assumptions, especially with respect to intangible assets. These estimates and assumptions are inherently uncertain, and as a result, actual results may differ from estimates. Significant estimates include, but are not limited to, future expected cash flows, useful lives and discount rates. During the measurement period, which is one year from the acquisition date, we may record adjustments to the assets acquired and liabilities assumed, with a corresponding offset to either goodwill or gain, depending on whether the fair value of purchase consideration is in excess of or less than net assets acquired. Upon the conclusion of the measurement period, any subsequent adjustments are recorded to earnings. Transaction costs associated with business combinations are expensed as incurred.

Asset Acquisitions

When the Company acquires assets and liabilities that do not constitute a business, the fair value of the purchase consideration, including transaction costs of the asset acquisition, is assumed to be equal to the fair value of the net assets acquired and is allocated to the individual assets and liabilities assumed based on their relative fair values. Contingent consideration associated with the acquisition is generally recognized when the contingency is resolved. No goodwill is recognized in an asset acquisition. Transaction costs associated with asset acquisitions are capitalized as part of the investment.

Equity Method Investments

When the Company acquires a noncontrolling interest in an entity where it is not the primary beneficiary, does not control any of the ongoing activities of the entity, and does not meet consolidation requirements of ASC 810, Consolidation of Variable Interest Entities, the investment is initially recognized as an equity method investment at cost. Any basis difference related to the property, plant and equipment will be amortized over the estimated economic useful life of the underlying long-lived assets. A basis difference related to the PPA will be amortized over the remaining term of the PPA. Transactions costs associated with equity method investments are capitalized as part of the investment.

Noncontrolling Interests

Noncontrolling interests represent the portion of the Company’s net income (loss), net assets and comprehensive income (loss) that is not allocable to the Company and is calculated based on ownership percentage, for applicable projects.

For the noncontrolling interests in the Company’s Panhandle 1, Panhandle 2, Post Rock, Logan's Gap and Amazon Wind Farm Fowler Ridge projects, and the Company's Gulf Wind project prior to the acquisition of the noncontrolling interests in July 2015, the Company has determined that the operating partnership agreements do not allocate economic benefits pro rata to its two classes of investors and the appropriate methodology for calculating the noncontrolling interest balance that reflects the substantive profit sharing arrangement is a balance sheet approach using the hypothetical liquidation at book value ("HLBV") method.

Under the HLBV method, the amounts reported as noncontrolling interest in the consolidated balance sheets and consolidated statements of operations represent the amounts the third party would hypothetically receive at each balance sheet reporting date under the liquidation provisions of the operating partnership agreement assuming the net assets of the projects were liquidated at recorded amounts determined in accordance with U.S. GAAP and distributed to the investors. The noncontrolling interest in the results of operations and comprehensive income (loss) is determined as the difference in noncontrolling interests in the consolidated balance sheets at the start and end of each reporting period, after taking into account any capital transactions between the projects and the third party. The noncontrolling interest balances in the projects are reported as a component of equity in the consolidated balance sheets.

Foreign Currency Translation

The assets and liabilities of foreign subsidiaries, where the local currency is the functional currency, are translated from their respective functional currencies into U.S. dollars at the rates in effect at the balance sheet date and revenue and expense amounts are translated at average rates during the period, with resulting foreign currency translation adjustments recorded in other comprehensive income (loss), net of tax, in the accompanying consolidated statements of stockholders’ equity and comprehensive income (loss). Where the U.S. dollar is the functional currency, re-measurement adjustments are recorded in other (expense) income, net in the accompanying consolidated statements of operations.

Concentrations of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist primarily of cash and cash equivalents, trade receivables, reimbursable interconnection costs and derivative instruments. The Company’s cash and cash equivalents are with high quality institutions. The Company has exposure to credit risk to the extent cash and cash equivalent balances, including restricted cash, exceed amounts covered by federal deposit insurance; however, the Company believes that its credit risk is immaterial. In addition, reimbursable interconnection costs are with large creditworthy utility companies and the Company’s derivative instruments are placed with counterparties that are creditworthy institutions.

The Company sells electricity and RECs primarily to creditworthy utilities under long-term, fixed-priced power sale arrangements ("PSAs"). During the year ended December 31, 2015, Standard & Poor’s Rating Services ("S&P") further downgraded the credit rating of the Puerto Rico Electric Power Authority ("PREPA") from CCC to CC. Through December 31, 2015, Moody’s Investor

Service's credit rating of PREPA remains unchanged at Caa3. As of February 29, 2016, PREPA was current with respect to payments due under the PPA and the next payment will be due from PREPA under the PPA on approximately March 18, 2016.

The table below presents significant customers who accounted for greater than 10% of total revenue, and PREPA, and the related maximum amount of credit loss based on their percentages of total trade receivables as of December 31, 2015, 2014 and 2013:

	Year ended December 31,					
	2015		2014		2013	
	Revenue	Trade Receivables	Revenue	Trade Receivables	Revenue	Trade Receivables
San Diego Gas & Electric	17.07 %	17.03 %	22.09 %	14.13 %	16.31 %	26.21 %
PREPA	8.42 %	8.80 %	9.29 %	6.91 %	8.21 %	16.88 %

The Independent Electricity System Operator ("IESO") of Ontario, Canada is the customer for each of the Company's Grand, K2 and South Kent projects. The Company accounts for these projects under the equity method of accounting and as a result, the Company's ownership interest in these projects is recorded in equity in earnings (losses) in unconsolidated investments and not in revenue. As such, IESO is not included in the foregoing table of significant customers. However, we rely on a limited number of key power purchasers, including IESO, and face a concentration of credit risk from IESO as a customer.

Fair Value of Financial Instruments

ASC 820, Fair Value Measurements, defines fair value as the price at which an asset could be exchanged or a liability transferred in an orderly transaction between knowledgeable, willing parties in the principal or most advantageous market for the asset or liability. Where available, fair value is based on observable market prices or derived from such prices. Where observable prices or inputs are not available, valuation models are applied which may involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity. See Note 13, Fair Value Measurements.

U.S. Treasury Grants

The Company received U.S. Treasury grants on certain wind power projects as defined under Section 1603 of the American Recovery and Reinvestment Act of 2009, as amended by the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of December 2010, upon approval by the U.S. Treasury Department. The Company records the U.S. Treasury grant proceeds as a deduction from the carrying amount of the related asset which results in a reduction of depreciation expense over the life of the asset. The Company records a catch-up adjustment in the period in which the grant is approved to recognize the portion of the grant that proportionally matches the depreciation for the period between the date of placement in service of the wind power project and approval by the U.S. Treasury Department. See Note 4, Property, Plant and Equipment.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash balances and highly-liquid investments with original maturities of three months or less.

Restricted Cash

Restricted cash consists of cash balances which are restricted as to withdrawal or usage and includes cash to collateralize bank letters of credit related primarily to interconnection rights, PSAs and for certain reserves required under the Company's loan agreements.

Trade Receivables

The Company's trade receivables are generated by selling energy and renewable energy credits in the California, Texas, Nevada, Manitoba (Canada), Puerto Rico and Chilean energy markets, primarily to creditworthy utilities. The Company believes that all amounts are collectible and an allowance for doubtful accounts is not required as of December 31, 2015 and 2014.

Reimbursable Interconnection Costs

The Company may, from time to time, pay to construct interconnection network upgrades on behalf of the Company's utility customers. The interconnection upgrades are owned by each utility customer who will reimburse the Company with interest either when the project reaches commercial operation or as energy is delivered over the life of the PPA.

Turbine Advances

Turbine advances represent amounts advanced to turbine suppliers for the manufacture of wind turbines in accordance with turbine supply agreements for the Company's wind power projects and for which the Company has not taken title. Turbine advances are reclassified to construction in progress when the Company takes legal title to the related turbines and are reclassified to property, plant and equipment when the project achieves commercial operation. Depreciation does not commence until projects enter commercial operation and turbine assets are placed in service.

Construction in Progress

Construction in progress represents the accumulated costs of projects in construction. Construction costs include turbines for which the Company has taken legal title, civil engineering, electrical and other related costs. Other capitalized costs include reclassified deferred development costs, amortization of intangible assets, amortization of deferred financing costs, capitalized interest and other costs required to place a project into commercial operation. Deferred development costs represent the accumulated costs of initial permitting, environmental reviews, land rights and obligations and preliminary design and engineering work. The Company expenses all project development costs until a project is determined to be technically feasible and likely to achieve commercial success. The Company begins capitalizing deferred development costs as a component of construction in progress on the date the project commences construction. Once the project achieves commercial operation, the Company reclassifies the amounts recorded in construction in progress to property, plant and equipment.

Finite-Lived Intangible Assets and Liability

Finite-lived intangible assets include PPAs, easements, land options and mining rights. PPAs obtained through acquisitions are valued at the time of acquisition and the difference between the contract price and the estimated fair value results in an intangible asset or an intangible liability. If the contract price is higher than the estimated fair value, the Company will recognize an intangible asset. If the contract price is lower than the estimated fair value, the Company will recognize an intangible liability. Easements, land options and mining rights are recognized at the carryover basis from the seller.

The Company amortizes its intangible asset and liability associated with PPAs using the straight-line method over the remaining term of the related PPA. At the date of acquisition, the weighted average amortization period of the intangible asset associated with the PPA is approximately 15 years and the weighted average amortization period of the intangible liability is approximately 17 years. The Company amortizes easements, land options and mining rights using the straight-line method over the term of their estimated useful lives, which represents the term of the easements and land option and mining rights agreements, ranging from approximately 5-25 years. The Company periodically evaluates whether events or changes in circumstances have occurred that indicate the carrying amount of finite-lived intangible assets may not be recoverable, or information indicates that impairment may exist.

Property, Plant and Equipment

Property, plant and equipment represents the costs of completed and operational projects transferred from construction in progress, as well as land, computer equipment and software, furniture and fixtures, leasehold improvements and other equipment. Property, plant and equipment are stated at cost, less accumulated depreciation. Depreciation is calculated using the straight-line method over the respective assets' useful lives. Wind farms for which construction began before 2011 are depreciated over 20 years and wind farms for which construction began after 2011 are depreciated over 25 years. The remaining assets are depreciated over two to five years. Improvements to property, plant and equipment deemed to extend the useful economic life of an asset are capitalized. Repair and maintenance costs are expensed as incurred.

Accounting for Impairment of Long-Lived Assets

The Company periodically evaluates long-lived assets for potential impairment whenever events or changes in circumstances have occurred that indicate that impairment may exist, or the carrying amount of the long-lived asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable based on its estimated future undiscounted cash flows. An impairment loss is calculated based on the excess of the carrying value of the long-lived asset over the fair value of such long-lived asset, with the fair value determined based on an estimate of discounted future cash flows. During the year ended December 31, 2015, the

Company recorded impairment charges of $0.4 million related to the write-off of certain furniture, fixtures and equipment in project expenses in the consolidated statements of operations.

Derivatives

The Company may enter into interest rate swaps, interest rate caps, forwards and other agreements to manage its interest rate, electricity price and foreign exchange rate risk. The Company recognizes its derivative instruments as assets or liabilities at fair value in the consolidated balance sheets, unless the derivative instruments qualify for the "normal purchase normal sale" ("NPNS") scope exception to derivative accounting. The Company does not have contracts subject to master netting agreements with counterparties, as such assets and liabilities are presented gross on the consolidated balance sheets.

Contracts used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as NPNS. NPNS contracts do not meet the definition of derivatives, and therefore, contracts associated with the sale of energy are recognized as electricity sales and contracts associated with the production of electricity are recognized as project expense on the consolidated statements of operations.

Accounting for changes in the fair value of a derivative instrument depends on whether it has been designated as part of a hedging relationship and on the type of hedging relationship. For derivative instruments that qualify and are designated as cash flow hedges, the effective portion of change in fair value of the derivative is reported as a component of other comprehensive income (loss) ("OCI"), until the contract settles and the hedged item is recognized in earnings. The ineffective portion of change in fair value is recorded as a component of net income (loss) on the consolidated statements of operations. The Company discontinues hedge accounting when it has determined that a derivative contract no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When the Company discontinues hedge accounting, associated deferred amounts are immediately recognized into earnings and future changes in fair value, if any, are recognized in earnings. For undesignated derivative instruments, the change in fair value is reported as a component of net income (loss) on the consolidated statements of operations.

Deferred Financing Costs

Financing costs incurred in connection with obtaining construction and term financing are deferred and amortized over the lives of the respective loans using the effective-interest method. Deferred financing costs are capitalized and recorded as an offset to the respective loans in the Company's consolidated balance sheets and are amortized to interest expense in the consolidated statements of operations. Financing costs related to the revolving credit facility are capitalized and recorded as a long-term asset in the Company's consolidated balance sheets and are amortized to interest expense in the Company's consolidated statements of operations, over the life of its life using the effective-interest method.

Income Taxes

The Company accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. The Company recognizes deferred tax assets to the extent that it believes these assets are more likely than not to be realized. In making such a determination, the Company considers all available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning and results of recent operations. If the Company determines that it would be able to realize its deferred tax assets in the future in excess of their net recorded amount, it would make an adjustment to the deferred tax asset valuation allowance, which would reduce the provision for income taxes. The Company records uncertain tax positions in accordance with ASC 740, Income Taxes, on the basis of a two-step process whereby (1) it determines whether it is more likely than not that the tax positions will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, it recognizes the largest amount of tax benefit that is more than 50% likely to be realized upon ultimate settlement with the related tax authority. The Company has a policy to classify interest and penalties associated with uncertain tax positions together with the related liability, and the expenses incurred

related to such accruals, if any, are included in the provision for income taxes.
Contingent Liabilities
The Company’s contingent liabilities represent deferred and contingent obligations related to projects either acquired through business combinations or asset acquisitions. Contingent obligations that are acquired through business combinations are recorded at fair value on the date of acquisition while contingent obligations that are acquired through asset acquisitions are recorded generally when the contingency is resolved. The Company’s contingent liabilities related to turbine availability warranties with

turbine manufacturers and turbine availability guarantees associated with long-term turbine service arrangements are reported at net realizable value. Pursuant to these warranties and guarantees, if a turbine operates at less than minimum availability during the warranty or guarantee period, the manufacturer or service provider is obligated to pay, as liquidated damages, an amount for each percent that the turbine operates below the minimum availability threshold. In addition, pursuant to certain of these warranties and guarantees, if a turbine operates at more than a specified availability during the warranty or guarantee period, the Company has an obligation to pay a bonus to the turbine manufacturer or service provider.

Asset Retirement Obligation

The Company records asset retirement obligations ("AROs") for the estimated costs of decommissioning turbines, removing above-ground installations and restoring sites, at the time when a contractual decommissioning obligation is incurred. AROs represent the present value of the expected costs and timing of the related decommissioning activities. The ARO assets and liabilities are recorded in property, plant and equipment and other long-term liabilities, respectively, in the consolidated balance sheets. The Company records accretion expense, which represents the increase in the asset retirement obligations, over the remaining or operational life of the associated wind project. Accretion expense is recorded as cost of revenue in the consolidated statements of operations using accretion rates based on credit adjusted risk-free interest rates. Changes resulting from revisions to the timing or amount of the original estimate of cash flows are recognized as an increase or a decrease in the asset retirement cost, or income when the asset retirement cost is depleted.

Revenue Recognition

The Company sells electricity and related renewable energy credits under the terms of the PSAs or at market prices. Revenue is recognized based upon the amount of electricity delivered at rates specified under the contracts, or at market prices for spot market transactions, assuming all other revenue recognition criteria are met. When renewable energy credits are sold as a separate component, revenue is recognized at the time title to the energy credits is transferred to the buyer. Depending on the terms of the PSA, the Company may account for the contracts as operating leases pursuant to ASC 840, Leases, or derivative instruments pursuant to ASC 815, Derivatives and Hedging. In considering ASC 840, Leases, it was determined that certain of the Company's PSAs are operating leases. ASC 840, Leases, requires minimum lease payments to be recognized over the term of the lease and contingent rents to be recorded when the achievement of the contingency becomes probable. All energy sales under the PSAs are considered contingent rent due to the inherent uncertainty and variability. None of the operating leases have minimum lease payments; therefore, revenue from these contracts and any related renewable energy attributes are recognized as electricity sales when delivered. Contracts that meet the NPNS scope exception to derivative accounting are accounted for under the accrual method, where revenues are recorded in the period they are earned.

Energy derivative instruments that reduce exposure to changes in commodity prices may allow the Company to lock in a fixed price per MWh for a specified amount of annual electricity generation over the life of the swap contract. Monthly settlement amounts under energy hedges are accounted for as energy derivative settlements in the consolidated statements of operations. Changes in the fair value of energy hedges are recorded in electricity sales in the consolidated statements of operations.

The Company recognizes revenue for warranty settlements and liquidated damages from turbine manufacturers in other revenue upon resolution of outstanding contingencies. Any cash receipts for amounts subject to future adjustment or repayment are deferred in other liabilities until the final settlement amount is considered fixed and determinable.

Cost of Revenue

The Company’s cost of revenue is comprised of direct costs of operating and maintaining its wind project facilities, including labor, turbine service arrangements, land lease royalties, depreciation, accretion, property taxes and insurance.

Stock-Based Compensation

The Company accounts for stock-based compensation related to stock options granted to employees by estimating the fair value of the stock-based awards using the Black-Scholes option-pricing model. The Black-Scholes option pricing model includes assumptions regarding dividend yields, expected volatility, expected option term, expected forfeiture rate and risk-free interest rates. Expense is recognized by amortizing the fair value of the stock options granted using a straight-line method over the applicable vesting period; accordingly, stock based compensation is netted for estimated forfeitures. The Company estimates expected volatility based on the historical volatility of comparable publicly traded companies for a period that is equal to the expected term of the options. The risk-free interest rate is based on the U.S. treasury yield curve in effect at the time of grant for a period commensurate with the estimated expected term of the stock option. The expected term of options granted is derived using the "simplified" method as allowed under the provisions of the ASC 718, Compensation—Stock Compensation, and represents the period of time that options granted are expected to be outstanding.

The Company accounts for stock-based compensation related to restricted stock award and restricted stock unit grants by amortizing the fair value of the restricted stock award grants, which is the grant date market price, over the applicable vesting period. For certain restricted stock award grants, the Company measures the fair value at the grant date using a Monte Carlo simulation model and amortizes the fair value over the longer of the requisite period or performance period. The Monte Carlo simulation model includes assumptions regarding dividend yields, expected volatility, risk-free interest rates and initial total shareholder return ("TSR") performance.

Stock-based compensation expense is recorded as a component of general and administrative expenses in the Company’s consolidated statements of operations.

Comprehensive Income (Loss)

Comprehensive income (loss) consists of net income (loss) and other comprehensive income (loss), net of tax. Other comprehensive income (loss), net of tax included in accumulated other comprehensive income (loss) in the accompanying consolidated statements of stockholders’ equity, is comprised primarily of changes in foreign currency translation adjustments and the effective portion of changes in the fair value of derivatives designated as hedges.

Segment Data and Geographic Information

Segment data

Operating segments are defined as components of a company about which separate financial information is available that is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance. The Company’s chief operating decision maker is the chief executive officer. Based on the financial information presented to and reviewed by the chief operating decision maker in deciding how to allocate the resources and in assessing the Company’s performance, the Company has determined its wind projects represent individual operating segments with similar economic characteristics that meet the criteria for aggregation into a single reporting segment for financial statement purposes.

Geographic information

The table below provides information, by country, about the Company’s consolidated operations. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located (in thousands):

	Revenue			Property, Plant and Equipment, net (including Construction in Progress)	
	Year ended December 31,			December 31,	
	2015	2014	2013	2015	2014
United States	$258,542	$201,408	$161,505	$ 2,791,259	$ 1,810,414
Canada	39,178	46,593	40,068	184,115	233,690
Chile	32,111	17,492	—	319,246	332,947
Total	$329,831	$265,493	$201,573	$ 3,294,620	$ 2,377,051

Recently Issued Accounting Standards

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, "Leases," which requires lessees to recognize right-of-use assets and lease liabilities, for all leases, with the exception of short-term leases, at the commencement date of each lease. Under the new guidance, lessor accounting is largely unchanged. ASU 2016-02 simplifies the accounting for sale and leaseback transactions primarily because lessees must recognize lease assets and liabilities. ASU 2016-02 is effective for annual periods beginning after December 15, 2018, and interim periods within those annual periods. Early adoption is permitted. The amendments of this update should be applied using a modified retrospective approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented. The Company is currently assessing the future impact of this update on its consolidated financial statements and related disclosures and expects to adopt this update beginning January 1, 2019.

In November 2015, the FASB issued ASU 2015-17, "Income Taxes: Balance Sheet Classification of Deferred Taxes," which eliminates the current requirement for organizations to present deferred tax liabilities and assets as current and non-current in a classified balance sheet. Instead, organizations will be required to classify all deferred tax assets and liabilities as non-current. ASU 2015-17 is effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The amendments may be applied prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. Early adoption is permitted for financial statements that have not been previously issued. The Company early adopted ASU 2015-17 for the year ended December 31, 2015 and has applied the guidance prospectively. No changes have been made to the prior period presentation.
In September 2015, the FASB issued ASU 2015-16, "Business Combinations: Simplifying the Accounting for Measurement-Period Adjustments," which requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments under ASU 2015-16 require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. ASU 2015-16 also requires an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods, if the adjustment to the provisional amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for annual reporting periods beginning after December 15, 2015 and interim periods within those fiscal years. The amendments in this update should be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. The Company will adopt ASU 2015-16, effective January 1, 2016. The adoption of ASU 2015-16 is not expected to have a material impact on the Company's consolidated financial statements and related disclosures.
In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers: Deferral of the Effective Date" to amend ASU 2015-09 "Revenue from Contracts with Customers" to defer the effective date of ASU 2014-09 for all entities by one year. The guidance in ASU 2014-09 provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. Lease contracts within the scope of ASC 840, "Leases", are specifically excluded from ASU No. 2014-09. As a result of this amendment, ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted only as of annual reporting periods beginning after December 15, 2015 and interim periods within those fiscal years. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption, through a cumulative adjustment. In June 2015, the FASB voted to defer the effective date by one year, with early adoption permitted as of the original effective date. The Company is currently assessing the future impact of this update on its consolidated financial statements and related disclosures and expects to adopt this update beginning January 1, 2018.
In August 2015, the FASB issued ASU 2015-13, "Derivatives and Hedging: Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets" to allow the application of the normal purchases and normal sales scope exception to certain electricity contracts within nodal energy markets. The amendments specify that the purchase or sale of electricity on a forward basis within nodal energy markets does not cause that contract to fail to meet the physical delivery criterion of the normal purchases and normal sales scope exception. The amendments in this update are effective upon issuance and are in line with the Company's current accounting policies. The adoption of ASU 2015-13 did not have an impact to the Company's consolidated financial statements and related disclosures.
In June 2015, the FASB issued ASU 2015-10, "Technical Corrections and Improvements" which covers a wide range of topics in the Accounting Standards Codification (the "Codification"). The amendments in this update represent changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the

Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost on most entities. The amendments in ASU 2015-10 were effective immediately upon issuance and the adoption did not have material impact on the Company's consolidated financial statements and related disclosures.

In April 2015, the FASB issued ASU 2015-03, "Interest – Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. ASU 2015-03 is effective for public companies for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years and should be applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. Upon transition, an entity is required to comply with the applicable disclosures for a change in accounting principle. The Company adopted ASU 2015-03 in April 2015 and applied the change in accounting principle to the consolidated financial statements as of December 31, 2015. As a result, the Company reclassified $26.3 million and $36.8 million in total deferred financing costs to long-term debt, of which $3.7 million and $11.9 million have been reclassified to current portion of long-term debt, as of December 31, 2015 and December 31, 2014, respectively, on the Company’s consolidated balance sheets. Deferred financing costs related to the Company’s revolving credit facility remain classified as an asset on the Company’s consolidated balance sheets. The adoption of ASU 2015-3 had no impact on the Company’s results of operations and cash flows.

In February 2015, the FASB issued ASU 2015-02, "Consolidation: Amendments to the Consolidation Analysis" to modify the analysis that companies must perform in order to determine whether a legal entity should be consolidated. ASU 2015-02 simplifies current guidance by reducing the number of consolidation models; eliminating the risk that a reporting entity may have to consolidate based on a fee arrangement with another legal entity; placing more weight on the risk of loss in order to identify the party that has a controlling financial interest; reducing the number of instances that related party guidance needs to be applied when determining the party that has a controlling financial interest; and changing rules for companies in certain industries that ordinarily employ limited partnership or VIE structures. ASU 2015-02 is effective for public companies for fiscal years beginning after December 15, 2015 and interim periods within those fiscal periods. Early adoption on a modified retrospective or full retrospective basis is permitted. The Company will adopt ASU 2015-16, effective January 1, 2016, and is currently assessing the impact to the Company’s consolidated financial statements and related disclosures.

In August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements – Going Concern: Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern" which requires an entity’s management to evaluate whether there is substantial doubt about the entity’s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for interim and annual periods beginning after December 15, 2016, with early adoption permitted for interim and annual reporting periods for which the financial statements have not been previously issued. The Company is currently assessing the future impact of this update on its consolidated financial statements and related disclosures and expects to adopt this update beginning January 1, 2017.

In June 2014, the FASB issued ASU 2014-12, "Compensation – Stock Compensation" which requires an entity to treat a performance target that affects vesting that could be achieved after an employee completes the requisite service period as a performance condition. The performance target should not be reflected in estimating the grant-date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. ASU 2014-12 is effective for interim and annual periods beginning after December 15, 2015, with early adoption permitted either prospectively or retrospectively to all prior periods presented. The Company will adopt ASU 2014-12, effective January 1, 2016 and does not anticipate that the adoption of this update will have a material impact on its consolidated financial statements and related disclosures.

3. Acquisitions

Business Combinations

Wind Capital Group Acquisition

On May 15, 2015, pursuant to a Purchase and Sale Agreement, the Company acquired 100% of the membership interests in Lost Creek Wind Finco, LLC ("Lost Creek Finco") from Wind Capital Group LLC, an unrelated third party, and 100% of the membership interests in Lincoln County Wind Project Holdco, LLC ("Lincoln County

Holdco") from Lincoln County Wind Project Finco, LLC, an unrelated third party. Lost Creek Finco owns 100% of the Class B membership interests in Lost Creek Wind Holdco, LLC (“Lost Creek Wind Holdco”), a company which owns a 100% interest in the Lost Creek wind project. Lincoln County Holdco owns 100% of the Class B membership interests in Post Rock Wind Power Project, LLC, a company which owns a 100% interest in the Post Rock wind project. The acquisition of 100% of the membership interests in Lost Creek Finco and Lincoln County Holdco was for an aggregate consideration of approximately $242.0 million, paid at closing. The Company also assumed certain project level indebtedness and ordinary course performance guarantees securing project obligations. Lost Creek is a 150 MW wind project in King City, Missouri, and Post Rock is a 201MW wind project in Ellsworth and Lincoln Counties, Kansas.

The Company acquired assets and operating contracts for Lost Creek and Post Rock, including assumed liabilities. The identifiable assets and liabilities assumed were recorded at their fair values, which corresponded to the sum of the cash purchase price and the fair value of the other investors' noncontrolling interests.

The fair value of the assets acquired and liabilities assumed in connection with the acquisition are as follows (in thousands):

	May 15, 2015
Cash and cash equivalents	$3,501
Restricted cash, current	11,787
Trade receivables	7,910
Prepaid expenses	1,232
Other current assets	444
Restricted cash	4,592
Property, plant and equipment	543,347
Finite-lived intangible assets	97,400
Other assets	17,632
Accounts payable and other accrued liabilities	(2,611)
Accrued interest	(951)
Derivative liabilities, current	(3,759)
Current portion of long-term debt, net of financing costs	(7,463)
Finite-lived intangible liabilities	(60,300)
Asset retirement obligations	(7,192)
Long-term debt, net of financing costs	(108,838)
Derivative liabilities	(14,631)
Total consideration before temporary equity and noncontrolling interests	482,100
Less: temporary equity	(35,000)
Less: noncontrolling interests	(205,100)
Total consideration after temporary equity and noncontrolling interests	$242,000

Current assets, non-current restricted cash, accounts payable and other accrued liabilities and accrued interest were recorded at carrying value, which is representative of the fair value on the date of acquisition. Property, plant and equipment, finite-lived intangible asset, finite-lived intangible liability and debt were recorded at fair value estimated using the income approach. The fair values of other assets, derivatives and asset retirement obligations were recorded at fair value using a combination of market data, operational data and discounted cash flows and were adjusted by a discount rate factor reflecting current market conditions at the time of acquisition.

The noncontrolling interest in Post Rock was recorded at fair value estimated using a projected cash flow stream of distributable cash and tax benefits anticipated based on the existing Partnership Agreement, discounted to present value with a discount rate reflecting the estimated return on investment required by participants in the tax equity market. The noncontrolling interest in Lost Creek was recorded at fair value estimated using the purchase price from a purchase agreement executed on May 15, 2015 between the Company and the tax equity investor.

The accounting for this acquisition is preliminary. The fair value estimates for the assets acquired and liabilities assumed were based on preliminary calculations and valuations, and the estimates and assumptions are subject to change as additional information is obtained for the estimates during the measurement period (up to one year from the acquisition date). During the three months ended December 31, 2015, the Company adjusted the initial valuation and increased property, plant and equipment by $2.0 million and decreased other assets by $2.3 million. Additionally, the Company increased asset retirement obligations and other accrued liabilities by $0.2 million and decreased derivatives liabilities, current by $0.5 million. These changes are as a result of the updated inputs, assumptions and methodologies

used in determining the fair value of these assets and liabilities.
The Company incurred transaction-related expenses of $1.7 million which were recorded in net gain (loss) on transactions in the consolidated statements of operations for the year ended December 31, 2015.

On July 30, 2015, the Company acquired 100% of the Class A membership interests in Lost Creek Wind Holdco for a cash purchase price of approximately $35.2 million. As a result, Lost Creek became wholly owned as of July 30, 2015.

The Company has determined that the operating partnership agreement does not allocate economic benefits pro rata to its two classes of investors and will use the HLBV method to calculate the noncontrolling interest balance that reflects the substantive profit sharing arrangement. Below is a description of the allocation of distributions related to the Post Rock.

Allocation of Distributions

In accordance with the terms of the operating agreement of Post Rock, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 20, 2023, the Class A Members shall receive 40% of all distributions from Post Rock. If the flip point has not occurred by November 20, 2023, then prior to the earlier of the flip point or November 20, 2027, the Class A Members shall receive 60% of all distributions from Post Rock. If the flip point has not occurred by November 20, 2027, the Class A Members shall receive 100% of all distributions from Post Rock until the flip point occurs. After the flip point, the Class A Members will receive 10% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash, provided that distributions related to certain payments under a Build Out Agreement between Post Rock and the Company are made to the Class A members.

Allocation of Tax Items

Prior to the flip point, Post Rock's tax items consisting of income, gain, loss and deductions, or the Tax Items, are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 10% of the Tax Items and the balance will be received by the Class B Member. Tax items attributable to the liquidation of derivative contracts are allocated 4.95% to the Class A Members and 95.05% to the Class B Member.

Logan’s Gap Acquisition

On December 19, 2014, the Company acquired 100% of the membership interests in the Logan’s Gap wind project, through the acquisition of Logan’s Gap B Member LLC, from Pattern Development, for a purchase price of approximately $15.1 million and an assumed contingent liability to a third party in the amount of $8.0 million associated with the close of construction financing and the achievement of either commercial operation or tax equity funding. The wind project achieved commercial operation in September 2015, and is located in Comanche County, Texas. The construction of the project was being financed primarily by construction debt and the Company. Following construction, the institutional tax equity investors invested in the project, pursuant to an executed equity commitment agreement, so that the construction loan was paid and that long term financing for the project is equity based.

Following the achievement of commercial operation, in September 2015, the Company and certain tax equity investors made capital contributions to fund the repayment of the Logan's Gap construction loan. As a result, the Company and the tax equity investors hold initial ownership interests of 82% and 18%, respectively, in the project’s distributable cash flows.

The Company acquired the assets and operating contracts for Logan’s Gap, including assumed liabilities. The identifiable assets acquired and liabilities assumed were recorded at their fair values which corresponded to the sum of the cash purchase price.

The accounting for the Logan’s Gap acquisition was completed as of March 31, 2015 at which point the fair values became final. The following table summarizes the provisional amounts recognized for assets acquired and liabilities assumed as of December 19, 2014, as well as adjustments made through March 31, 2015, when the allocation became final. During the quarter ended March 31, 2015, the Company adjusted the initial valuation and increased prepaid expenses and other current assets by $0.1 million, increased deferred financing costs, current by $0.8 million, increased construction in progress by $0.1 million and increased accrued construction costs by $0.9 million.
The consolidated fair value of the assets acquired and liabilities assumed in connection with the Logan’s Gap acquisition are as follows (in thousands):

	December 19, 2014
Cash and cash equivalents	$2
Restricted cash, current	5,003
Prepaid expenses and other current assets	1,790
Deferred financing costs, current	2,882
Construction in progress	23,821
Property, plant and equipment	116
Other assets	80
Accrued construction costs	(5,617)
Current portion of contingent liabilities	(7,975)
Related party payable	(5,003)
Total consideration	$15,099

Current assets, current liabilities, property, plant and equipment, other assets, accrued construction costs and related party payable were recorded at carrying value, which is representative of the fair value on the date of acquisition. Construction in progress was recorded at fair value which is representative of the development effort, including the developer’s profit, and contracts acquired on the date of acquisition.
The Company recorded $8.0 million in contingent obligations, payable to a third party, at fair value upon the acquisition of the project. As of December 31, 2015, $6.3 million of the contingent obligation has been paid with the remaining $1.7 million payable recorded in accounts payable and other accrued liabilities.
The Company incurred $0.1 million and $0.3 million of transaction-related expenses which were recorded in net gain (loss) on transactions in the consolidated statements of operations for the years ended December 31, 2015 and 2014, respectively.
The Company has determined that the operating partnership agreement does not allocate economic benefits pro rata to its two classes of investors and will use the HLBV method to calculate the noncontrolling interest balance that reflects the substantive profit sharing arrangement. Below is a description of the allocation of distributions related to Logan's Gap.
Allocation of Distributions
In accordance with the terms of the operating agreement of Logan’s Gap, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or December 17, 2024, the Class A Members shall receive approximately 18% of all distributions from Logan’s Gap. After the flip point, the Class A Members will receive 5.1% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash. Distributions related to the sale of RECs are made primarily to the Class B Member.
Allocation of Tax Items
Prior to the flip point, Logan’s Gap's tax items consisting of income, gain, loss and deductions, or the Tax Items, are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5.1% of the Tax Items and the balance will be received by the Class B Member. Tax items related to the sale of RECs are allocated primarily to the Class B Member.

Panhandle 2 Acquisition

On November 10, 2014, the Company acquired 100% of the membership interests in the Panhandle 2 wind project through the acquisition of Panhandle B Member 2 LLC, from Pattern Development, for a purchase price of approximately $123.8 million.

Concurrent with the closing, certain tax equity investors made capital contributions to acquire 100% of the Class A membership interests in Panhandle 2 and were admitted as noncontrolling members in the entity and the Company received 100% of the Class B membership interest, resulting in the tax equity investors and the Company holding initial ownership interests of 19% and 81%, respectively, in the project's distributable cash flows. The 182 MW wind project, located in Carson County, Texas, achieved commercial operation on November 7, 2014.

The Company acquired the assets and operating contracts for Panhandle 2, including assumed liabilities. The identifiable assets acquired and liabilities assumed were recorded at their fair values which corresponded to the sum of the cash purchase price. Since the closing of the tax equity event occurred simultaneously with the acquisition, the Company considered the price paid by the noncontrolling investors (an entry price) to be a clear indication of what a market participant would pay and a reasonable measurement of fair value (an exit price) of the noncontrolling interest at initial recognition. The short-term debt presented in the table below consists of a construction loan that was repaid in full following the acquisition.

The accounting for the Panhandle 2 acquisition was completed as of March 31, 2015 at which point the fair values became final. The following table summarizes the final amounts recognized for assets acquired and liabilities assumed as of November 10, 2014.

The consolidated fair value of the assets acquired and liabilities assumed in connection with the Panhandle 2 acquisition are as follows (in thousands):

	November 10, 2014
Cash and cash equivalents	$240
Trade receivables	1,156
Prepaid expenses and other current assets	28,997
Property, plant and equipment	315,109
Accrued construction costs	(24,197)
Related party payable	(121)
Short-term debt	(195,351)
Asset retirement obligation	(2,003)
Total consideration	$123,830

Current assets, accrued construction costs and related party payable were recorded at carrying value, which is representative of the fair value on the date of acquisition. In addition, the short-term debt was recorded at carrying value, representative of the fair value, which was repaid immediately after acquisition.

Property, plant and equipment were recorded at the cost of construction plus the developer's profit margin, which represents fair value. The asset retirement obligation was recorded at fair value using a combination of market data, operational data and discounted cash flows and was adjusted by a discount rate factor reflecting then current market conditions.

The Company incurred $0.2 million and $0.6 million of transaction-related expenses which were recorded in net gain (loss) on transactions in the consolidated statements of operations for the years ended December 31, 2014 and 2013, respectively.

The Company has determined that the operating partnership agreement does not allocate economic benefits pro rata to its two classes of investors and will use the HLBV method to calculate the noncontrolling interest balance that reflects the substantive profit sharing arrangement. Below is a description of the allocation of distributions related to the Panhandle 2.

Allocation of Distributions

In accordance with the terms of the operating agreement of Panhandle 2, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 30, 2023, the Class A Members shall receive approximately 19% of all distributions from Panhandle 2. If the amount of distributions is below a determined schedule, the Class A Members shall receive 40% of distributable cash and the Class B Member shall receive the remainder of distributable cash. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A

Members' tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash. Distributions related to the sale of RECs are made primarily to the Class B Member.

Allocation of Tax Items

Prior to the flip point, Panhandle 2's tax items consisting of income, gain, loss and deductions, or the Tax Items, are allocated as follows: 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5%, and the balance will be received by the Class B Member. Tax items related to the sale of RECs are allocated primarily to the Class B Member.

Panhandle 1 Acquisition

On June 30, 2014, the Company acquired 100% of the Class B membership interest in the Panhandle 1 wind project, representing a 79% initial ownership interest in the project's distributable cash flow, through the acquisition of Panhandle Wind Holdings LLC, from Pattern Development, for a purchase price of approximately $124.4 million. The 218 MW wind project, located in Carson County, Texas, achieved commercial operation on June 25, 2014. Concurrent with the closing, certain tax equity investors made capital contributions to acquire 100% of the Class A membership interests in Panhandle 1 and have been admitted as noncontrolling members in the entity, with a 21% initial ownership interest in the project's distributable cash flow.

The Company acquired the assets and operating contracts for Panhandle 1, including assumed liabilities. The identifiable assets acquired and liabilities assumed were recorded at their fair values, which corresponded to the sum of the cash purchase price and the initial balance of the other investors' noncontrolling interests. Since the closing of the tax equity event occurred simultaneously with the acquisition, the Company considered the price paid by the noncontrolling investors (an entry price) to be a clear indication of what a market participant would pay and a reasonable measurement of fair value (an exit price) of the noncontrolling interest at initial recognition.

The accounting for the Panhandle 1 acquisition was completed as of December 31, 2014 at which point the fair values became final. The following table summarizes the provisional amounts recognized for assets acquired and liabilities assumed as of June 30, 2014, as well as adjustments made through December 31, 2014, when the allocation became final.

The consolidated fair value of the assets acquired and liabilities assumed in connection with the Panhandle 1 acquisition are as follows (in thousands):

	June 30, 2014
Cash and cash equivalents	$1,038
Trade receivables	1,850
Prepaid expenses and other current assets	71
Restricted cash, non-current	14,293
Property, plant and equipment	332,953
Accounts payable and other accrued liabilities	(148)
Accrued construction costs	(12,806)
Related party payable	(44)
Asset retirement obligation	(2,557)
Total consideration before non-controlling interest	334,650
Less: tax equity noncontrolling interest contributions	(210,250)
Total consideration after non-controlling interest	$124,400

Current assets, restricted cash, current liabilities, accrued construction costs and related party payable were recorded at carrying value, which is representative of the fair value on the date of acquisition.

Property, plant and equipment were recorded at the cost of construction plus the developer's profit margin, which represents fair value. The asset retirement obligation was recorded at fair value using a combination of market data, operational data and discounted cash flows and was adjusted by a discount rate factor reflecting then current market conditions.

The Company incurred $0.5 million of transaction-related expenses which were recorded in net gain (loss) on transactions in the consolidated statements of operations for the year ended December 31, 2014.

The Company has determined that the operating partnership agreement does not allocate economic benefits pro rata to its two classes of investors and will use the HLBV method to calculate the noncontrolling interest balance that reflects the substantive profit sharing arrangement. Below is a description of the allocation of distributions related to Panhandle 1.

Allocation of Distributions

In accordance with the terms of the operating agreement of Panhandle 1, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or June 29, 2023, the Class A Members shall receive approximately 21% of all distributions from Panhandle 1. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash. Distributions related to the sale of RECs are made primarily to the Class B Member.

Allocation of Tax Items

Prior to the flip point, Panhandle 1's tax items consisting of income, gain, loss and deductions, or the Tax Items, are allocated as follows: prior to the flip point, 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5% of the Tax Items and the balance will be received by the Class B Member. Tax items related to the sale of RECs are allocated primarily to the Class B Member.

El Arrayán Acquisition

On June 25, 2014, the Company acquired 100% of the issued and outstanding common stock of AEI El Arrayán Chile SpA ("AEI El Arrayán"), an entity holding a 38.5% indirect interest in El Arrayán, for a total purchase price of $45.3 million, pursuant to the terms of a Stock Purchase Agreement (the "Agreement"). The Company owned a 31.5% indirect interest in El Arrayán prior to acquiring the additional 38.5% interest in order to obtain majority control (70%) of the project, as a part of its growth strategy. El Arrayán is a 115 MW wind power project, located in Ovalle, Chile, which achieved commercial operation on June 4, 2014.

Prior to the acquisition, the Company accounted for the investment under the equity method of accounting. Because the Company acquired an additional 38.5% indirect interest in El Arrayán, in accordance with ASC 805, Business Combinations, the acquisition was accounted for as a "business combination achieved in stages." Accordingly, the Company remeasured the previously held equity interest in El Arrayán and adjusted it to fair value based on the Company’s existing equity interest in the fair value of the underlying assets and liabilities of El Arrayán. The fair value of the Company’s equity interest at the acquisition date was $37.0 million (31.5% of implied equity value of $117.5 million per below). The difference between the fair value of the Company’s ownership in El Arrayán and the Company’s carrying value of its investment of $19.1 million resulted in a gain of $17.9 million recorded in net gain (loss) on transactions in the consolidated statements of operations for the year ended December 31, 2014. The Company recognized additional deferred tax liability due to differences in accounting and tax bases resulting from the Company’s existing ownership interest in El Arrayán, which has been included in the consolidated statements of operations. The Company now holds a 70% controlling interest in the wind project and consolidates the accounts of El Arrayán. In accordance with ASC 805, the Company considered whether any control premium or noncontrolling interest discount adjustment was necessary; however, based upon the relevant facts, the Company concluded that a proportionate allocation of the total fair value was reasonable. Therefore, no control premium or noncontrolling interest discount was applied in calculating the fair value of the Company's equity interest.

The Company acquired the assets and operating contracts for AEI El Arrayán, including assumed liabilities. The identifiable assets acquired and liabilities assumed were recorded at their fair values.

The accounting for the AEI El Arrayán acquisition was completed as of December 31, 2014 at which point the fair values became final. The following table summarizes the final amounts recognized for assets acquired and liabilities assumed as of June 25, 2014.
The consolidated fair value of the assets acquired and liabilities assumed in connection with the AEI El Arrayán acquisition are as follows (in thousands):

	Consolidated interest June 25, 2014
Cash and cash equivalents	$713
Trade receivables	3,829
VAT receivable	17,031
Prepaid expenses and other current assets	174
Restricted cash, non-current	10,392
Property, plant and equipment	341,417
Intangible assets	1,121
Net deferred tax assets	5,455
Accounts payable and other accrued liabilities	(6,830)
Accrued construction costs	(9,495)
Accrued interest	(2,592)
Derivative liabilities, current	(1,942)
Current portion of long-term debt	(16,586)
Long-term debt	(209,295)
Derivative liabilities, non-current	(501)
Asset retirement obligation	(2,354)
Net deferred tax liabilities	(13,001)
Total consideration	117,536
Less: non-controlling interest	(35,259)
Controlling interest	$82,277

Current assets, restricted cash, deferred tax assets, accounts payable and other accrued liabilities, accrued construction costs, debt, accrued interest and deferred tax liabilities were recorded at carrying value, which is representative of the fair value on the date of acquisition. Debt and derivative liabilities were recorded at fair value. Property, plant and equipment were recorded at the cost of construction plus the developer's profit margin, which represents fair value. The asset retirement obligation was recorded at fair value using a combination of market data, operational data and discounted cash flows and was adjusted by a discount rate factor reflecting then current market conditions.
The Company recognized deferred tax liabilities due to differences in accounting and tax bases resulting from the Company's acquisition of incremental interest in El Arrayán and the remeasurement of the project's remaining noncontrolling interest at fair value.
The Company incurred $0.4 million of transaction-related expenses which were recorded in net gain (loss) on transactions in the consolidated statements of operations for the year ended December 31, 2014.

Supplemental pro forma data (unaudited)

The unaudited pro forma statements of operations data below gives effect to the Lost Creek, Post Rock, Logan's Gap, Panhandle 2, Panhandle 1, and El Arrayán acquisitions as if they had occurred on January 1, 2014. The pro forma net loss for the years ended December 31, 2015 and 2014 was adjusted to exclude nonrecurring transaction related expenses of $1.8 million and $2.9 million, respectively. In addition, the 2014 pro forma net loss was adjusted to exclude a nonrecurring gain of $17.9 million, upon the acquisition of AEI El Arrayán. The unaudited pro forma data is presented for illustrative purposes only and is not intended to be indicative of actual results that would have been achieved had these acquisitions been consummated as of January 1, 2014. The unaudited pro forma data should not be considered representative of the Company's future financial condition or results of operations.

	Year ended December 31,	
Unaudited pro forma data (in thousands)	2015	2014
Pro forma total revenue	$351,094	$326,094
Pro forma total expenses	411,746	389,180
Pro forma net loss	(60,652)	(63,086)
Less: pro forma net loss attributable to noncontrolling interest	(29,091)	(21,591)
Pro forma net loss attributable to Pattern Energy	$(31,561)	$(41,495)

Prior to the acquisition of AEI El Arrayán, net loss was recorded in equity in (losses) earnings in unconsolidated investments in the consolidated statements of operations. From January 1, 2014 to June 25, 2014, the Company recorded net loss of $0.4 million in equity in (losses) earnings on unconsolidated investments related to El Arrayán.

The following table presents the amounts included in the consolidated statements of operations for Lost Creek and Post Rock since their respective dates of acquisition:

	Year ended December 31,
Unaudited data (in thousands)	2015
Total revenue	$31,093
Total expenses	34,574
Net loss	(3,481)
Less: net loss attributable to noncontrolling interest	(5,114)
Net loss attributable to Pattern Energy	$1,633

Noncontrolling Interest Acquisition

Gulf Wind

On July 28, 2015, the Company acquired Pattern Development's 27% interest in the Gulf Wind project for a cash purchase price of approximately $13.0 million. Concurrently, the Company acquired 100% of MetLife Capital, Limited Partnership's Class A membership interest in the Gulf Wind project for a cash purchase price of approximately $72.8 million. As a result of the acquisitions, the Company owns 100% of the membership interests in the Gulf Wind project. The Company's additional paid-in capital was increased by $17.2 million, representing the difference between the aggregate purchase price and carrying values of the noncontrolling interests as of July 28, 2015.

Asset Acquisition

Amazon Wind Farm Fowler Ridge

On April 29, 2015, the Company acquired 100% of the membership interests in Fowler Ridge IV Wind Farm LLC through the acquisition of Fowler Ridge IV B Member LLC from Pattern Development, pursuant to a Purchase and Sale Agreement, for a purchase price of approximately $37.5 million, paid at closing, in addition to $0.6 million of capitalized transaction-related expenses, and contingent payments of up to $29.1 million, payable upon tax equity funding. The 150MW wind project, named Amazon Wind Farm Fowler Ridge, located in Benton County, Indiana, achieved commercial operation on December 4, 2015. Following the achievement of commercial operation, the Company and certain tax equity investors made capital contributions to

fund the repayment of the construction loan. As a result, the Company and the tax equity investors hold initial ownership interests of 65% and 35%, respectively, in the project's initial distributable cash flows.

The Company acquired certain assets and assumed certain liabilities of Amazon Wind Farm Fowler Ridge, including various operating contracts, deferred development costs, tangible assets, real property interests, governmental approvals and other assets. The fair value of the purchase consideration, including transaction costs of the asset acquisition, is allocated to the relative fair value of the individual assets and liabilities. The preliminary fair value of the assets acquired and liabilities assumed in connection with the Amazon Wind Farm Fowler Ridge acquisition are as follows (in thousands):

	April 29, 2015
Prepaid expenses and other current assets	$1,753
Deferred financing costs, current	2,132
Turbine advances	4,000
Construction in progress	34,487
Finite-lived intangible assets, net of accumulated amortization	2,247
Accrued construction costs	(6,549)
Total consideration	$38,070

The accounting for this acquisition is preliminary. The fair value estimates for the assets acquired and liabilities assumed were based on preliminary calculations and valuations, and the estimates and assumptions are subject to change as additional information is obtained. During the three months ended December 31, 2015, the Company adjusted the initial valuation and increased construction in progress by $0.1 million related to the capitalization of additional transaction-related expenses, resulting in total capitalized transaction-related expenses of $0.6 million.

In connection with the acquisition, the Company may make additional contingent payments of up to $29.1 million, consisting of a $25.1 million fixed amount and up to an additional $4.0 million, as calculated based on final budget to actual amounts, both of which are payable to Pattern Development upon tax equity funding. On December 18, 2015, pursuant to the Purchase and Sale Agreement between the Company and Pattern Development, the Company settled the contingent obligation and made a payment of $27.2 million upon tax equity funding.

The Company also acquired $14.8 million of contingent obligations, which were paid as of December 31, 2015, consisting in part of a $5.0 million contingent obligation, which was paid subsequent to the close of construction financing, and assumption of an estimated $7.3 million third party contingent liability, which was recognized and paid subsequent to the acquisition at the time of commissioning of the first wind turbine in October 2015. The Company also assumed a $2.5 million liability, which was also recognized and paid in October 2015 to a third party upon energization of the project's substation.

In addition, the Company acquired an agreement between Pattern Development and an unrelated third party, whereby the unrelated third party is entitled to 1% of the gross revenue received by the project under the PPA, which is estimated to be approximately $2.5 million over 13 years.

The Company has determined that the operating partnership agreement does not allocate economic benefits pro rata to its two classes of investors and will use the HLBV method to calculate the noncontrolling interest balance that reflects the substantive profit sharing arrangement. Below is a description of the allocation of distributions related to Amazon Wind Farm Fowler Ridge.

Allocation of Distributions

In accordance with the terms of the operating agreement of Amazon Wind Farm Fowler Ridge, prior to the earlier of the flip point (the point at which the Class A Members have realized a specified internal rate of return) or November 30, 2025, the Class A Members shall receive approximately 35% of all distributions from Amazon Wind Farm Fowler Ridge. After the flip point, the Class A Members will receive 5% of the distributions, but not less than the amount that will offset certain Class A Member tax liabilities. In each case, the Class B Member will receive the remainder of all distributable cash. Distributions related to the sale of RECs are made primarily to the Class B Member.

Allocation of Tax Items

Prior to the flip point, Amazon Wind Farm Fowler Ridge's tax items consisting of income, gain, loss and deductions, or the Tax Items, are allocated as follows: 99% of the Tax Items are allocated to the Class A Members and 1% to the Class B Member. After the flip point, the Class A Members receive 5% of the Tax Items and the balance will be received by the Class B Member. Tax items related to the sale of RECs not sold to the power purchaser under the power purchase agreement are allocated for the first 5 years primarily to the Class A Members and thereafter primarily to the Class B Member.

Equity Method Investments

On June 17, 2015, the Company acquired from Pattern Development a one-third equity interest in K2 for approximately $128.0 million, in addition to $0.4 million of capitalized transaction-related expenses, plus assumed estimated proportionate debt at term conversion of approximately $221.8 million. In November 2015, upon term conversion, an additional $4.0 million of contingent consideration became due payable to the seller, resulting in an adjusted purchase price of approximately $132.4 million. K2 is a joint venture established to develop, construct and own a wind power project located in Ontario, Canada. The project has a 20-year PPA and commenced commercial operation in May 2015. The Company’s investment in K2 was funded through general corporate funds and borrowings under the revolving credit facility. The Company is a noncontrolling investor in K2, but does have significant influence over K2. Accordingly, the investment is accounted for under the equity method of accounting.

The cost of the Company’s investment in K2 was $115.6 million higher than the Company’s underlying equity in the net assets of K2. This equity method basis difference was comprised of $61.9 million related to property, plant and equipment and $53.7 million related to the PPA. The accounting for the acquisition is preliminary. The basis differences were based on preliminary calculations and valuations, and the estimates and assumptions are subject to change as additional information is obtained.

4. Property, Plant and Equipment

The following presents the categories within property, plant and equipment (in thousands):

	December 31, 2015	2014
Operating wind farms	$3,700,140	$2,624,640
Furniture, fixtures and equipment	3,500	4,366
Land	141	141
Subtotal	3,703,781	2,629,147
Less: accumulated depreciation	(409,161)	(278,291)
Property, plant and equipment, net	$3,294,620	$2,350,856

The Company recorded depreciation expense related to property, plant and equipment of $141.2 million, $102.9 million and $82.0 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The Company has received $253.4 million from the U.S Department of the Treasury under cash grants in lieu of investment tax credits ("Cash Grant") for its Ocotillo, Santa Isabel and Spring Valley wind farms. The Company recorded the cash proceeds as a deduction from the carrying amount of the related wind farm assets which resulted in the assets being recorded at lower amounts and reduced depreciation expense in the consolidated statements of operations by approximately $11.4 million, $12.7 million and $13.0 million for the years ended December 31, 2015, 2014 and 2013, respectively.

5. Finite-Lived Intangible Assets and Liability

The following presents the major components of the finite-lived intangible assets and liability (in thousands):

	December 31, 2015			
	Weighted Average Remaining Life	Gross	Accumulated Amortization	Net
Intangible assets				
Power purchase agreement	14	$97,400	$(4,114)	$93,286
Other intangible assets	17	4,679	(243)	$4,436
Total intangible assets		$102,079	$(4,357)	$97,722
Intangible liability				
Power purchase agreement	17	$(60,300)	$2,168	$(58,132)

	December 31, 2014			
	Weighted Average Remaining Life	Gross	Accumulated Amortization	Net
Other intangible assets	17	$1,411	$(154)	$1,257

The Company presents amortization of the PPA asset and PPA liability as electricity sales in the consolidated statements of operations, resulting in a decrease of $4.1 million and an increase of $2.2 million in electricity sales, respectively, for the year ended December 31, 2015. For the years ended December 31, 2015, 2014 and 2013, the Company recorded amortization expense of $0.1 million, $0.2 million and zero, respectively, related to other intangible assets in depreciation, amortization and accretion in the consolidated statements of operations.

The following table presents estimated future amortization for the next five years related to the PPA asset and PPA liability and other intangible assets:

Year ended December 31,	Power purchase agreements, net	Other intangible assets
2016	$3,049	$277
2017	3,031	352
2018	3,031	277
2019	3,031	277
2020	3,049	277
Thereafter	19,963	2,976

6. Unconsolidated Investments

The following projects are accounted for under the equity method of accounting and are presented in the Company's consolidated balance sheets for the periods below (in thousands):

	December 31,		Percentage of Ownership December 31,	
	2015	2014	2015	2014
South Kent	$6,185	$17,360	50.0 %	50.0 %
Grand	5,735	11,719	45.0 %	45.0 %
K2	104,553	—	33.3 %	N/A
Unconsolidated investments	$116,473	$29,079		

South Kent

The Company is a noncontrolling investor in a joint venture established to develop, construct, and own a wind power project located in Ontario, Canada. The project has a 20-year PPA, and commenced commercial operation in March 2014.

Grand
The Company is a noncontrolling investor in a joint venture established to develop, construct, and own a wind power project located in Ontario, Canada. The project has a 20-year PPA and commenced commercial operation in December 2014.
K2
The Company is a noncontrolling investor in a joint venture established to develop, construct and own a wind power project located in Ontario, Canada. The project has a 20-year PPA and commenced commercial operation in May 2015. See Note 3, Acquisitions - Equity Method Investments, for disclosure on the acquisition of the one-third equity interest in K2.
El Arrayán
On June 25, 2014, the Company increased its total ownership interest in El Arrayán to 70%. See Note 3, Acquisitions - Business Combinations - El Arrayán Acquisition, for disclosure on the acquisition of El Arrayán. As such, the Company has consolidated the operations of El Arrayán as of the acquisition date and is no longer accounting for this investment under the equity method of accounting.
The following summarizes the aggregated balance sheets and statements of operations for K2 as of December 31, 2015 and for the year ended December 31, 2015 and statements of operations for El Arrayán for the year ended December 31, 2014, prior to its consolidation in June 2014 and December 31, 2013, pursuant to Regulation S-X Rule 4-08 (g) (in thousands):

	December 31, 2015
Current assets	$46,342
Non-current assets	631,151
Total assets	$677,493
Current liabilities	$46,901
Non-current liabilities	617,460
Total liabilities	664,361
Total equity	13,132
Total liabilities and equity	$677,493

	Year Ended December 31,		
	2015	2014	2013
Revenue	$52,130	$1,821	$—
Cost of revenue	18,450	1,060	15
Operating expenses	3,140	682	900
Other expense	10,061	1,341	26
Net (loss) income	$20,479	$(1,262)	$(941)

7. Accounts Payable and Other Accrued Liabilities

The following table presents the components of accounts payable and other accrued liabilities (in thousands):

	December 31,	
	2015	2014
Accounts payable	$625	$673
Other accrued liabilities	9,583	7,892
Warranty settlement payments	—	639
LTSA/PPE upgrades liability	4,909	680
Turbine operations and maintenance payable	985	1,310
Purchase agreement obligations	5,749	—
Land lease rent payable	2,513	2,115
Spare-parts inventory payables	1,181	—
Payroll liabilities	5,345	4,453
Property tax payable	11,145	4,625
Sales tax payable	741	2,406
Accounts payable and other accrued liabilities	$42,776	$24,793

8. Revolving Credit Facility

On November 15, 2012, certain subsidiaries of the Company entered into a $120.0 million revolving credit agreement ("Existing Credit Agreement") for working capital with a four-year term comprised of a revolving loan facility and a letter of credit facility. The revolving credit agreement has an "accordion feature" under which the subsidiaries have the right to increase available borrowings by up to $35.0 million if its lenders or other additional lenders are willing to lend on the same terms and meet certain other conditions.

During 2014, certain subsidiaries of the Company entered into an Amended and Restated Credit and Guaranty Agreement which increased the available borrowings under the Existing Credit Agreement from $145.0 million to $350.0 million. The maturity date was also extended to December 2018.

During 2015, certain subsidiaries of the Company entered into two separate amendments to the Amended and Restated Credit and Guaranty Agreement which added two additional lenders to the facility and increased available borrowings under the Existing Credit Agreement from $350.0 million to $500.0 million ("Revolving Credit Facility"). The Revolving Credit Facility is secured by pledges of the capital stock and ownership interests in certain of the Company’s holding company subsidiaries. The Revolving Credit Facility contains a broad range of covenants that, subject to certain exceptions, restrict the Company’s holding company subsidiaries' ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay distributions and change its business. As of December 31, 2015, the Company's holding company subsidiaries are in compliance with covenants contained in the Revolving Credit Facility.

The loans under our Revolving Credit Facility are either base rate loans or Eurodollar rate loans. The base rate loans accrue interest at the fluctuating rate per annum equal to the greatest of the (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the Eurodollar rate that would be in effect for a Eurodollar rate loan with an interest period of one month plus 1.0%, plus an applicable margin ranging from 1.25% to 1.75% (corresponding to applicable leverage ratios of the borrower). The Eurodollar rate loans accrue interest at a rate per annum equal to LIBOR, as published by Reuters plus an applicable margin ranging from 2.25% to 2.75% (corresponding to applicable leverage ratios of the borrower). Under the Revolving Credit Facility, we pay a revolving commitment fee equal to the average of the daily difference between revolving commitments and the total utilization of revolving commitments times 0.50%. We also pay letter of credit fees.

As of December 31, 2015 and 2014, outstanding loan balances under the Revolving Credit Facility were $355.0 million and $50.0 million, respectively. In addition, as of December 31, 2015 and 2014, letters of credit of $27.2 million and $45.1 million, respectively, were issued under the Revolving Credit Facility.

9. Long Term Debt

The Company’s long term project debt for the following periods is presented below (in thousands):

	December 31,		As of December 31, 2015		
	2015	2014	Contractual Interest Rate	Effective Interest Rate	Maturity
Project-level					
Fixed interest rate					
El Arrayán EKF term loan	$107,160	$109,630	5.56 %	5.56 %	March 2029
St. Joseph term loan	—	189,472	5.88 %	5.95 %	May 2031
Santa Isabel term loan	109,973	112,609	4.57 %	4.57 %	September 2033
Variable interest rate					
Logan's Gap construction loan	—	58,691	1.57 %	1.57 %	December 2015
Gulf Wind term loan	—	156,122	3.28 %	6.59 % (1)	March 2020
Ocotillo commercial term loan (5)	208,119	222,175	2.36 %	3.77 % (1) (2)	August 2020
Lost Creek term loan	110,846	—	2.19 %	6.49 % (1)	September 2027
El Arrayán commercial term loan	97,418	99,665	3.17 %	5.65 % (1)	March 2029
Spring Valley term loan	132,670	167,261	2.36 %	4.89 % (1)	June 2030
Ocotillo development term loan	104,500	106,700	2.71 %	4.37 % (1)	August 2033
St. Joseph term loan (5)	158,181	—	2.46 %	3.84 %	November 2033
Imputed interest rate					
Hatchet Ridge financing lease obligation	214,580	228,288	1.43 %	1.43 %	December 2032
	1,243,447	1,450,613			
Unamortized premium, net (3)	1,380	—			
Unamortized financing costs	(26,303)	(36,755)			
Current portion (including construction loans) (4)	(44,144)	(109,693)			
Long-term debt, less current portion (including construction loans)	$1,174,380	$1,304,165			

(1) Includes impact of interest rate derivatives. See Note 11, Derivative Instruments, for discussion of interest rate derivatives.

(2) In October 2014, the Ocotillo financing agreement was amended to include a margin rate decrease of 1.0% for the commercial term loan.

(3) Amount is related to the Lost Creek term loan.

(4) Amount is presented net of the current portion of unamortized financing costs of $3.7 million and $11.9 million as of December 31, 2015 and 2014, respectively.

(5) The amortization for the Ocotillo commercial term loan and the St. Joseph term loan are through June 2030 and September 2036, respectively, which differs from the stated maturity date of such loans due to prepayment requirements.

The following are principal payments, excluding deferred financing costs, due under the Company's long-term project debt as of December 31, 2015 for the following years (in thousands):

	Amount
2016	$47,613
2017	51,705

2018	60,438
2019	66,304
2020	69,526
Thereafter	947,861
Total	$1,243,447

Interest and commitment fees incurred and interest expense for the long term debt, the revolving credit facility and convertible debt consisted of the following (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Interest and commitment fees incurred	$70,847	$59,864	$57,478
Capitalized interest, commitment fees, and letter of credit fees	(6,607)	(2,856)	(4,210)
Letter of credit fees incurred	4,572	4,377	3,530
Amortization of debt discount/premium, net	1,660	—	—
Amortization of financing costs	7,435	6,309	6,816
Interest expense	$77,907	$67,694	$63,614

Project-level Financing Arrangements

The Company typically finances its wind projects through project entity specific debt secured by each project's assets with no recourse to the Company. Typically, these financing arrangements provide for a construction loan, which upon completion may be converted into a term loan or repaid through capital contributions from the Company and tax equity investors.

Collateral for project level facilities typically include each project's tangible assets and contractual rights and cash on deposit with the depository agents. Each loan agreement contains a broad range of covenants that, subject to certain exceptions, restrict each project's ability to incur debt, grant liens, sell or lease certain assets, transfer equity interests, dissolve, make distributions and change their business. As of December 31, 2015, all projects were in compliance with their financing covenants.

The following is a summary of debt arrangements entered into, amended or acquired during the years ended December 31, 2015 and 2014, respectively.

St. Joseph

On November 17, 2015, St. Joseph extinguished its existing credit facility consisting of a term loan of approximately C$212.5 million and maturing in March 2031 and entered into a C$244.0 million credit agreement that provided a term loan facility, a letter of credit facility and an interest hedge facility (the "St. Joseph Credit Agreement") maturing in November 2033. Pursuant to the terms of the St. Joseph Credit Agreement, the prior lenders to the project were repaid in full with borrowings from a new group of lenders. The interest rate on the St. Joseph term loan was reduced from a fixed rate of 5.95% to a Canadian Dollar Offered Rate (CDOR) plus 1.625% (increasing by 0.125% every three years). The size of the St. Joseph Credit Agreement was increased to C$219.0 million to include finance fees and costs associated with the new arrangement. The St. Joseph Credit Agreement also established approximately C$25.0 million in new letter of credit facilities for the project to support various reserve requirements and security obligations under the power purchase agreement.

In connection with the St. Joseph Credit Agreement, St. Joseph entered into interest rate swaps with each of the new lenders to manage exposure to interest rate risk. The interest rate swaps were designed to effectively set 90% of the St. Joseph Credit Agreement interest rate at 4.0% (increasing by 0.125% every three years). See Note 11, Derivative Instruments, for additional information.

As a result of the repayment of the existing term loan of approximately C$212.5 million, the Company recognized a loss on debt extinguishment of approximately $0.8 million, which includes unamortized deferred financing costs and legal fees incurred as a result of the extinguishment, for the year ended December 31, 2015.

Spring Valley

On October 20, 2015, Spring Valley entered into an amendment to its financing agreement with existing lenders. Pursuant to the terms of the refinancing, the interest rate on the term loan for the facility was reduced from LIBOR plus 2.38% (increasing 0.25% every four years) to LIBOR plus 1.75% (increasing by 0.125% every four years). Through proceeds from the Revolving Credit Facility, the Company also made a prepayment of $29.7 million towards the outstanding principal balance on Spring Valley's term loan facility which reduced the outstanding balance of the term loan to approximately $133.2 million.

In connection with the prepayment of $29.7 million, the Company discontinued the cash flow hedge designation on a portion of the interest rate swap associated with the original outstanding principal balance prior to prepayment. See Note 11, Derivative Instruments, for additional information.

The Company accounted for the Spring Valley refinancing event as a debt modification for all lenders. In accordance with ASC 470-50, Debt Modifications and Extinguishments, the amendment fees of $0.9 million and the remaining $5.0 million of unamortized debt issuance costs related to the original debt will be amortized over the remaining term of the modified debt using the effective interest method.

Logan's Gap

In December 2014, Logan’s Gap entered into a $282.8 million financing agreement comprised of a $247.1 million construction loan and letter of credit facilities to provide letter of credit loans in an amount totaling up to $35.7 million. On September 18, 2015, the Company and certain tax equity investors made capital contributions to fund the repayment of the Logan's Gap construction loan. As of December 31, 2015, the balance of the construction loan was zero. See Note 15, Stockholders' Equity - Noncontrolling Interests, for additional information.

Lost Creek

On September 3, 2015, Lost Creek entered into a Second Amended and Restated Credit Agreement ("Lost Creek Term Loan")which, among other things, reduced the interest rate from LIBOR plus 2.75% (with periodic increases of 0.25%) to LIBOR plus 1.65% (increasing by 0.125% every four years) and extended the maturity of the Lost Creek Term Loan from March 2021 to September 2027. Under ASC 470-50, Debt Modifications and Extinguishments, these amendments to the Lost Creek Term Loan are considered a modification of debt on a lender-by-lender basis. As a result, the capitalized amendment fees of $1.5 million paid to lenders are amortized over the remaining term of the modified debt using the effective interest method. In addition, the Company expensed third party legal and other fees of approximately $0.7 million, which are included in other (expense) income, net in the Company's consolidated statements of operations.

The Lost Creek Term Loan includes a collateral agreement that requires proceeds from the sale of energy from the Lost Creek wind project be remitted directly to the depositary agent of the Lost Creek Term Loan to provide for debt service payments and operating costs required under the Lost Creek Term Loan. The Lost Creek Term Loan also replaced the existing debt service and operating and maintenance reserves with a $10.7 million revolving credit facility provided by certain lenders in the event Lost Creek is unable to make payments towards debt service reserve requirements and operating and maintenance reserve requirements.

The Lost Creek Term Loan is subject to certain covenants, including limitations on additional indebtedness, limitations on liens, requirements for periodic financial and operational information, and compliance with certain required financial ratios. The Lost Creek Term Loan also contains voluntary prepayment provisions which provide for the right to prepay the Lost Creek Term Loan without premium or penalty and contains mandatory prepayments for such events as upwind array events. As of December 31, 2015, there has been no requirement to make any such mandatory prepayments of amounts borrowed under the term loan. Additionally, the Lost Creek Term Loan restricts payment of dividends, distributions, and returns of capital to affiliates of Lost Creek unless provided by the Lost Creek Term Loan.

Gulf Wind

On July 28, 2015, the Company acquired the noncontrolling interests in the Gulf Wind project, resulting in a 100% ownership of the membership interests in the Gulf Wind project. See Note 15, Stockholders' Equity - Noncontrolling Interests, for additional information. Subsequent to the acquisitions, on July 30, 2015, the Company prepaid 100% of the outstanding balance of the Gulf Wind project’s term loan of $154.1 million, resulting in a loss on extinguishment of debt, primarily related to the write-off of deferred financing costs, of approximately $4.1 million. As a result of the early extinguishment of debt, the Company terminated the related interest rate swaps and cap. See Note 11, Derivative Instruments, for additional information.

Amazon Wind Farm Fowler Ridge

On April 29, 2015, Amazon Wind Farm Fowler Ridge entered into a $199.1 million construction loan facility and $22.5 million of letter of credit facilities, as required by the PPA and renewable energy credit agreement. The interest rate on the construction loan facility was 1.69%. Under the financing agreement, the construction loan facility will be repaid at the earlier of commercial operation or February 29, 2016, the scheduled maturity date, through capital contributions from both the tax equity investors and the Company.

The Company also entered into a Letter of Credit, Reimbursement and Loan Agreement pursuant to which the $11.2 million REC letter of credit facility expires on April 29, 2016 and the $11.3 million PPA letter of credit facility expires on April 29, 2020.

On December 18, 2015, the Company and certain tax equity investors made capital contributions to fund the repayment of the Amazon Wind Farm Fowler Ridge construction loan facility. As of December 31, 2015, the balance of the construction loan facility was zero. See Note 15, Stockholders' Equity - Noncontrolling Interests, for additional information.

El Arrayán

In May 2012, El Arrayán entered into a first lien senior secured credit agreement (“El Arrayán Credit Agreement”) which provides up to approximately $225.0 million in borrowings. Borrowings under the El Arrayán Credit Agreement were used to finance the construction of the El Arrayán wind project and are comprised of a commercial tranche of up to $100.0 million and an export credit agency tranche provided by Eksport Kredit Fonden of Denmark (“EKF Tranche”) of up to $110.0 million, and letters of credit facilities totaling up to $15.0 million. In connection with the El Arrayán Credit Agreement, the Company entered into interest rate swaps on 95.8% of the commercial tranche term loan. The project commenced commercial operations in June 2014 and the construction loan converted into term loans on August 14, 2014. The financing is non-recourse to El Arrayán.

The commercial tranche loan is a LIBOR loan and accrues interest at LIBOR plus 2.75% per annum from the closing until the sixth anniversary of closing, 3.00% from the sixth anniversary to the tenth anniversary of closing, 3.25% from the tenth anniversary to the fourteenth anniversary of closing, and 3.50% after the fourteenth anniversary of closing. The EKF Tranche term loan accrues interest at a fixed rate of 5.56%, in each case, plus a margin of 0.25% from the sixth anniversary to the tenth anniversary of the closing, 0.50% from the tenth anniversary to the fourteenth anniversary of closing, and 0.75% after the fourteenth anniversary of closing.

Financing Lease Obligations

In December 2010, Hatchet Ridge entered into a sale-leaseback agreement to finance the project facility for 22 years. The Company evaluated the agreement in accordance with ASC 840, Leases, and ASC 360, Property Plant and Equipment, and determined that due to continuing involvement with the project facility, the Company is precluded from treating the agreement as a sale-lease back transaction and accounts for the agreement as a financing lease obligation.

Collateral for the agreement includes Hatchet Ridge’s tangible assets and contractual rights and cash on deposit with the depository agent. Its loan agreement contains a broad range of covenants that, subject to certain exceptions, restrict Hatchet Ridge’s ability to incur debt, grant liens, sell or lease assets, transfer equity interests, dissolve, pay distributions and change its business.

Payments under the financing lease for the years ended December 31, 2015, 2014 and 2013, were $16.9 million, $15.0 million and $14.8 million, respectively.

Convertible Senior Notes due 2020

In July 2015, the Company issued $225.0 million aggregate principal amount of 4.00% convertible senior notes due 2020 ("2020 Notes"). The 2020 Notes bear interest at a rate of 4.00% per year, payable semiannually in arrears on January 15 and July 15 of each year, beginning on January 15, 2016. The 2020 Notes will mature on July 15, 2020. The 2020 Notes were sold in a private placement.

At any time prior to the close of business on the business day immediately preceding January 15, 2020, holders may convert the 2020 Notes under the following circumstances:

- during any calendar quarter commencing after the calendar quarter ending on September 30, 2015, if the last reported sale price of the Company’s Class A common stock for at least 20 trading days during a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day;
- during the five business day period after any 10 consecutive trading day period (the "measurement period") in which the trading price per $1,000 principal amount of notes for each trading day of the measurement period was less than 98% of the product of the last reported sale price of the Class A common stock and the conversion rate on each such

trading day;

- upon occurrence of specified corporate events; or
- at any time on or after January 15, 2020 until close of business on the second scheduled trading day immediately preceding the maturity date.

Upon conversion, the Company may, at its discretion, pay cash, shares of the Company's Class A common stock, or a combination of cash and stock.

The 2020 Notes will be converted at an initial conversation rate of 35.4925 shares of Class A common stock per $1,000 principal amount of 2020 Notes, which is equivalent to an initial conversion price of approximately $28.175 per share of Class A common stock. The conversion rate is subject to adjustment in some events (including, but not limited to, certain cash dividends made to holders of the Company's Class A common stock which exceed the initial dividend threshold of $0.363 per quarter per share). The conversion rate would be adjusted to offset the effect of the portion of the dividend in excess of $0.363. The conversion rate will not be adjusted for any accrued and unpaid interest. The 2020 Notes are not redeemable prior to maturity.

Upon the occurrence of certain fundamental changes involving the Company, holders of the 2020 Notes may require the Company to repurchase all or a portion of their 2020 Notes for cash at a price of 100% of the principal amount of the 2020 Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

The 2020 Notes are guaranteed on a senior unsecured basis by a subsidiary of the Company and are general unsecured obligations of the Company. The obligations rank senior in rights of payment to the Company's subordinated debt, equal in right of payment to the Company's unsubordinated debt and effectively junior in right of payment to any of the Company's secured indebtedness to the extent of the value of the assets securing such indebtedness.

The 2020 Notes are accounted for in accordance with ASC 470-20, Debt with Conversion and Other Options, and ASC 815, Derivatives and Hedging. Under ASC 815, issuers of certain convertible debt instruments are generally required to separately account for the conversion option of the convertible debt instrument as a derivative, unless it meets a scope exception which allows the issuer to classify the conversion option as equity. As the 2020 Notes have met the scope exception, the Company is required to separately account for the liability and equity components of the convertible debt instrument in accordance with ASC 470-20, Debt with Conversion and Other Options. The carrying amount of the liability component is determined based on the fair value of a similar liability without the conversion option. The market interest rate used in determining the liability component of the 2020 Notes was 6.6%. The amount of the equity component is then calculated by deducting the fair value of the liability component from the principal amount of the 2020 Notes.

The following table presents a summary of the equity and liability components of the 2020 Notes (in thousands):

	December 31, 2015
Principal	$225,000
Less:	
Unamortized debt discount	(22,624)
Unamortized financing costs	(5,014)
Carrying value of convertible senior notes	$197,362
Carrying value of the equity component [(1)]	$23,743

(1) Included in the consolidated balance sheets as additional paid-in capital, net of $0.7 million in equity issuance costs.

During the year ended December 31, 2015, in relation to the 2020 Notes, the Company recorded $3.8 million, $0.5 million and $1.8 million related to the contractual coupon interest, amortization of financing costs and amortization of debt discount, respectively, in interest expense in its consolidated statements of operations.

10. Asset Retirement Obligation

The Company's asset retirement obligations represent the estimated cost of decommissioning the turbines, removing above-ground installations and restoring the sites at the end of its estimated economic useful life. Effective January 1, 2015, the Company changed its estimate of the useful lives of wind farms for which construction began after 2011, from 20 years to 25 years. As a result, during the year ended December 31, 2015, the Company recorded a one-time adjustment of $1.9 million to reduce the carrying balance of the asset retirement obligations to reflect the change estimated useful life of the underlying wind farms and related estimate associated with the timing of the original undiscounted cash flows.

The following table presents a reconciliation of the beginning and ending aggregate carrying amounts of asset retirement obligation (in thousands):

	December 31, 2015	2014
Beginning asset retirement obligations	$29,272	$20,834
Net additions during the year	13,189	7,195
Foreign currency translation adjustment	(411)	(228)
Adjustment related to change in useful life	(1,907)	—
Accretion expense	2,054	1,471
Ending asset retirement obligations	$42,197	$29,272

11. Derivative Instruments

The Company employs a variety of derivative instruments to manage its exposure to fluctuations in electricity prices, interest rates and foreign currency exchange rates. Energy prices are subject to wide swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists primarily on variable-rate debt for which the cash flows vary based upon movement in market prices. Additionally, the Company is exposed to foreign currency exchange rate risk primarily from its business operations in Canada and Chile. The Company’s objectives for holding these derivative instruments include reducing, eliminating and efficiently managing the economic impact of these exposures as effectively as possible. We do not hedge all of our electricity price risk, interest rate risks, and foreign currency exchange rate risks, thereby exposing the unhedged portions to changes in market prices.

As of December 31, 2015, the Company had other energy-related contracts that did not meet the definition of a derivative instrument or qualified for the NPNS exception and were therefore exempt from fair value accounting treatment.

The following tables present the fair values of the Company's derivative instruments on a gross basis as reflected on the Company's consolidated balance sheets (in thousands):

	December 31, 2015			
	Derivative Assets		Derivative Liabilities	
	Current	Long-Term	Current	Long-Term
Fair Value of Designated Derivatives:				
Interest rate swaps	$—	$—	$10,034	$24,360
Fair Value of Undesignated Derivatives:				
Interest rate swaps	$—	$559	$4,309	$4,299
Energy derivative	20,856	42,827	—	—
Foreign currency forward contracts	3,482	628	—	—
Total Fair Value	$24,338	$44,014	$14,343	$28,659

	December 31, 2014			
	Derivative Assets		Derivative Liabilities	
	Current	Long-Term	Current	Long-Term
Fair Value of Designated Derivatives:				
Interest rate swaps	$—	$525	$12,904	$17,467
Fair Value of Undesignated Derivatives:				
Interest rate swaps	$—	$2,523	$3,403	$—
Interest rate cap	—	352	—	—
Energy derivative	18,506	45,969	—	—
Total Fair Value	$18,506	$49,369	$16,307	$17,467

The following table summarizes the notional amounts of the Company's outstanding derivative instruments (in thousands except for MWh):

		December 31,	
	Unit of Measure	2015	2014
Designated Derivative Instruments			
Interest rate swaps	USD	$379,808	$440,467
Interest rate swaps	CAD	$196,988	$—
Undesignated Derivative Instruments			
Interest rate swaps	USD	$275,424	$272,716
Interest rate cap	USD	$—	$42,102
Energy derivative	MWh	1,707,350	2,211,563
Foreign currency forward contracts	CAD	$62,300	$—

Derivatives Designated as Hedging Instruments

Cash Flow Hedges

The Company has interest rate swap agreements to hedge variable rate project-level debt. Under these interest rate swaps, the projects make fixed-rate interest payments and the counterparties to the agreements make variable-rate interest payments. For interest swaps that are designated and qualify as cash flow hedges, the effective portion of the gain or loss on the derivative is reported as a

component of accumulated other comprehensive loss and reclassified into earnings in the period or periods during which a cash settlement occurs. The designated interest rate swaps have remaining maturities ranging from approximately 11.8 years to 20.8 years.

The following table presents gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in accumulated other comprehensive loss, as well as amounts reclassified to earnings for the following periods (in thousands):

		Year Ended December 31,		
	Description	2015	2014	2013
Gains (losses) recognized in accumulated OCI	Effective portion of change in fair value	$(16,163)	$(33,444)	$24,932
Gains (losses) reclassified from accumulated OCI into:				
Interest expense	Derivative settlements	$12,234	$13,774	$11,943
Realized loss on designated derivatives, net	Termination of derivatives	$11,221	$—	$—
Loss (gain) on undesignated derivatives, net	De-designation of derivatives	$5,918	$—	$—
Gains (losses) recognized in interest expense	Ineffective portion	$(809)	$—	$—

The Company estimates that $10.0 million in accumulated other comprehensive loss will be reclassified into earnings over the next twelve months.

Spring Valley

On October 20, 2015, in connection with the amendment to Spring Valley's term loan, the Company made a prepayment of $29.7 million towards the outstanding principal balance on Spring Valley's term loan which reduced the balance to approximately $133.2 million. See Note 9, Long Term Debt - Spring Valley, for additional information. As a result, the Company discontinued the cash flow hedge designation on a portion of the interest rate swaps associated with the original outstanding principal balance prior to prepayment and reclassified approximately $5.9 million from accumulated other comprehensive loss to loss (gain) on undesignated derivatives in the Company's consolidated statements of operations.

Gulf Wind

On July 28, 2015, in connection with the early extinguishment of Gulf Wind's term loan, the Company terminated the related interest rate swaps which resulted in the reclassification of $11.2 million in accumulated other comprehensive loss to realized loss on designated derivatives, net in the consolidated statements of operations.

Derivatives Not Designated as Hedging Instruments

The following table presents gains and losses on derivatives not designated as hedges (in thousands):

			Year Ended December 31,		
Derivative Type	Financial Statement Line Item	Description	2015	2014	2013
Interest rate derivatives	(Loss) gain on undesignated derivatives, net	Change in fair value, net of settlements	$(5,758) (1)	$(11,668)	$15,601
Interest rate derivatives	(Loss) gain on undesignated derivatives, net	Derivative settlements	$(4,838)	$(4,075)	$(2,099)
Energy derivative	Electricity sales	Change in fair value, net of settlements	$(792)	$(3,878)	$(11,272)
Energy derivative	Electricity sales	Derivative settlements	$20,568	$13,525	$16,798
			$4,110	$—	$—

Foreign currency forward contracts	(Loss) gain on undesignated derivatives, net	Change in fair value, net of settlements			
Foreign currency forward contracts	(Loss) gain on undesignated derivatives, net	Derivative settlements	$996	$—	$—

(1) Amount includes the reclassification of $5.9 million from accumulated other comprehensive loss related to the dedesignation of certain interest rate derivative instruments at Spring Valley.

Interest Rate Derivatives

Interest Rate Swaps

The Company has interest rate swap agreements to hedge variable rate project-level debt. Under these interest rate swaps, the projects make fixed-rate interest payments and the counterparties to the agreements make variable-rate interest payments. For interest rate swaps that are not designated and do not qualify as cash flow hedges, the changes in fair value are recorded in (loss) gain on undesignated derivatives, net in the consolidated statements of operations as these hedges are not accounted for under hedge accounting. The undesignated interest rate swaps have remaining maturities ranging from approximately 5.3 years to 14.5 years.

Interest Rate Cap

In 2010, Gulf Wind entered into an interest rate cap to manage its exposure to future interest rates when its long-term debt was expected to be refinanced at the end of the ten-year term. The cap provided Gulf Wind the right to receive payments and protected the Company if future interest rates exceeded approximately 6.0%.

On July 28, 2015, in connection with the early extinguishment of Gulf Wind's term loan, the Company terminated the related interest rate cap which resulted in a net loss of $0.2 million, recognized in (loss) gain on undesignated derivatives, net in the consolidated statements of operations and primarily represents a realization of losses previously recorded within accumulated other comprehensive loss.

Energy Derivative

In 2010, Gulf Wind acquired an energy derivative instrument to manage its exposure to variable electricity prices over the life of the arrangement. The energy price swap fixes the price for a predetermined volume of production (the notional volume) over the life of the swap contract, through April 2019, by locking in a fixed price per MWh. The notional volume agreed to by the parties is approximately 504,220 MWh per year. The energy derivative instrument does not meet the criteria required to adopt hedge accounting. As a result, changes in fair value are recorded in electricity sales in the consolidated statements of operations.

Foreign Currency Forward Contracts

In January 2015, the Company established a currency risk management program. The objective of the program is to mitigate the foreign exchange rate risk arising from transactions or cash flows that have a direct or underlying exposure in non-U.S. dollar denominated currencies in order to reduce volatility in the Company’s cash flow, which may have an adverse impact to our short-term liquidity or financial condition. A majority of the Company’s power sale agreements and operating expenditures are transacted in U.S. dollars, with a growing portion transacted in currencies other than the U.S. dollar, primarily the Canadian dollar. In 2015, the Company entered into foreign currency forward contracts at various times to mitigate the currency exchange rate risk on Canadian dollar denominated cash flows. These instruments have remaining maturities ranging from one to eighteen months. The foreign currency forward contracts are considered non-designated derivative instruments and are not used for trading or speculative purposes. As a result, changes in fair value and settlements are recorded in (loss) gain on undesignated derivatives, net in the consolidated statements of operations.

12. Accumulated Other Comprehensive Loss

The following table summarizes changes in the accumulated other comprehensive loss balance, net of tax, by component:

	Foreign Currency	Effective Portion of Change in Fair Value of Derivatives	Proportionate Share of Equity Investee's OCI	Total
Balances at December 31, 2012	$(154)	$(43,877)	$(1,475)	$(45,506)
Other comprehensive (loss) income before reclassifications	(8,309)	24,932	2,473	19,096
Amounts reclassified from accumulated other comprehensive loss	—	11,943	—	11,943
Net current period other comprehensive (loss) income	(8,309)	36,875	2,473	31,039
Grand acquisition	—	—	(2,910)	(2,910)
Balances at December 31, 2013	$(8,463)	$(7,002)	$(1,912)	$(17,377)
Other comprehensive loss before reclassifications	(10,875)	(33,444)	(5,991)	(50,310)
Amounts reclassified from accumulated other comprehensive loss	—	13,774	—	13,774
Net current period other comprehensive loss	(10,875)	(19,670)	(5,991)	(36,536)
Balances at December 31, 2014	$(19,338)	$(26,672)	$(7,903)	$(53,913)
Other comprehensive loss before reclassifications	(28,947)	(16,163)	(6,640)	(51,750)
Amounts reclassified from accumulated other comprehensive loss due to termination/de-designation of interest rate derivatives	—	17,139	—	17,139
Amounts reclassified from accumulated other comprehensive loss	—	12,234	2,412	14,646
Net current period other comprehensive (loss) income	(28,947)	13,210	(4,228)	(19,965)
Balances at December 31, 2015	$(48,285)	$(13,462)	$(12,131)	$(73,878)
Less: accumulated other comprehensive loss attributable to noncontrolling interest, December 31, 2015	—	(553)	—	(553)
Accumulated other comprehensive loss attributable to Pattern Energy, December 31, 2015	$(48,285)	$(12,909)	$(12,131)	$(73,325)

13. Fair Value Measurements

The Company’s fair value measurements incorporate various factors, including the credit standing and performance risk of the counterparties, the applicable exit market, and specific risks inherent in the instrument. Nonperformance and credit risk adjustments on risk management instruments are based on current market inputs when available, such as credit default hedge spreads. When such information is not available, internal models may be used.

Assets and liabilities recorded at fair value in the consolidated financial statements are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to valuation of these assets or liabilities are set forth below.

Transfers between levels are recognized at the end of each quarter. The Company did not recognize any transfers between levels during the periods presented.

Level 1—Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2—Inputs (other than quoted prices included in Level 1) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3—Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities and which reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuations technique and the risk inherent in the inputs to the model.

Short-term Financial Instruments

Short-term financial instruments consist principally of cash and cash equivalents, restricted cash, trade receivables, current portion of prepaid expenses, related party receivable/payable, reimbursable interconnection costs, accounts payable and other accrued liabilities, accrued construction costs, accrued interest, dividends payable and the revolving credit facility. Based on the nature and short maturity of these instruments, their carrying cost approximates their fair value, and they are presented in the Company's financial statements at carrying cost. The fair values of cash and cash equivalents and restricted cash are classified as Level 1 in the fair value hierarchy.

Financial Instruments Measured at Fair Value on a Recurring Basis

The Company's financial assets and liabilities which require fair value measurement on a recurring basis are classified within the fair value hierarchy as follows (in thousands):

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets				
Interest rate swaps	$—	$559	$—	$559
Energy derivative	—	—	63,683	63,683
Foreign currency forward contracts	—	4,110	—	4,110
	$—	$4,669	$63,683	$68,352
Liabilities				
Interest rate swaps	$—	$43,002	$—	$43,002
Energy derivative	—	—	—	—
Foreign currency forward contracts	—	—	—	—
	$—	$43,002	$—	$43,002

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets				
Interest rate swaps	$—	$3,048	$—	$3,048
Interest rate cap	—	352	—	352
Energy derivative	—	—	64,475	64,475
	$—	$3,400	$64,475	$67,875
Liabilities				
Interest rate swaps	$—	$33,774	$—	$33,774
	$—	$33,774	$—	$33,774

Level 2 Inputs

Derivative instruments subject to re-measurement are presented in the financial statements at fair value. The Company's interest rate swaps and interest rate cap were valued by discounting the net cash flows using the forward LIBOR curve with the valuations adjusted by the Company's credit default hedge rate. The Company's foreign currency forward contracts were valued using the income approach based on the present value of the forward rates less the contract rates, multiplied by the notional amounts.

Level 3 Inputs

The fair value of the energy derivative instrument is determined based on a third-party valuation model. The methodology and inputs are evaluated by management for consistency and reasonableness by comparing inputs used by the third-party valuation provider to another third-party pricing service for identical or similar instruments and also agreeing inputs used in the third-party valuation model to the derivative contract for accuracy. Any significant changes are further evaluated for reasonableness by obtaining additional documentation from the third-party valuation provider.

The energy derivative instrument is valued by discounting the projected net cash flows over the remaining life of the derivative instrument using forward electricity prices which are derived from observable prices, such as forward gas curves, adjusted by a non-observable heat rate for when the contract term extends beyond a period for which market data is available. The significant unobservable input in calculating the fair value of the energy derivative instrument is forward electricity prices. Significant increases or decreases in this unobservable input would result in a significantly lower or higher fair value measurement.

The following table presents a reconciliation of the energy derivative contract measured at fair value on a recurring basis using significant unobservable inputs (in thousands):

	2015	2014
Balance at beginning of year	$64,475	$68,353
Total gains (losses) included in electricity sales	19,776	9,646
Settlements	(20,568)	(13,524)
Balance at end of year	$63,683	$64,475

During the years ended December 31, 2015, 2014 and 2013, the Company recognized unrealized losses on the energy derivative of $0.8 million, $3.9 million, and $11.3 million, respectively.

The valuation techniques and significant unobservable inputs used in recurring Level 3 fair value measurements were as follows (in thousands, for fair value):

December 31, 2015	Fair Value	Valuation Technique	Significant Unobservable Inputs	Range
Energy derivative	$63,683	Discounted cash flow	Forward electricity prices	$12.48 - $74.94[1]
			Discount rate	0.61% - 1.46%

December 31, 2014	Fair Value	Valuation Technique	Significant Unobservable Inputs	Range
Energy derivative	$64,475	Discounted cash flow	Forward electricity prices	$14.24 - $106.11[1]
			Discount rate	0.26% - 1.63%

(1) Represents price per MWh

Financial Instruments not Measured at Fair Value

The following table presents the carrying amount and fair value and the fair value hierarchy of the Company's financial liabilities that are not measured at fair value in the consolidated balance sheets as of December 31, 2015 and 2014, but for which fair value is disclosed (in thousands):

		Fair Value			
	As reflected on the balance sheet	Level 1	Level 2	Level 3	Total
December 31, 2015					
Convertible senior notes	$197,362	$—	$189,863	$—	$189,863
Long-term debt, including current portion	$1,218,524	$—	$1,192,286	$—	$1,192,286
December 31, 2014					
Long-term debt, including current portion	$1,413,858	$—	$1,416,744	$—	$1,416,744

Long term debt and the convertible senior notes are presented on the consolidated balance sheets, net of financing costs. The fair value of variable interest rate long-term debt is approximated by its carrying cost. The fair value of fixed interest rate long-term debt is estimated based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied, using the net present value of cash flow streams over the term using estimated market rates for similar instruments and remaining terms.

14. Income Taxes

The following table presents significant components of the provision for income taxes (in thousands):

	Year ended December 31,		
	2015	2014	2013
Current:			
Federal	$—	$—	$—
State	—	—	—
Foreign	489	182	—
Total current expense	489	182	—
Deferred:			
Federal	—	—	2,961
State	—	—	—
Foreign	4,454	2,954	1,585
Total deferred expense	4,454	2,954	4,546
Total provision for income taxes	$4,943	$3,136	$4,546

The following table presents the domestic and foreign components of net (loss) income before income tax provision (in thousands):

	Year ended December 31,		
	2015	2014	2013
U.S.	$(66,883)	$(34,788)	$4,022
Foreign	16,219	(2,075)	10,596
Total	$(50,664)	$(36,863)	$14,618

The following table presents a reconciliation of the statutory U.S. federal income tax rate to the Company's effective tax rate, as a percentage of income before taxes for the following periods:

	Year ended December 31,		
	2015	2014	2013
Computed tax at statutory rate	35.0 %	35.0 %	35.0 %
Adjustment for income in non-taxable entities allocable to noncontrolling interest	(13.0)%	(7.6)%	16.5 %
Foreign rate differential			
Tax rate differential on pre-tax book income, other	(6.6)%	5.6 %	2.1 %
Local tax on branch profits/(losses)—Puerto Rico	0.3 %	1.6 %	13.1 %
Permanent book/tax differences (domestic only)	(0.1)%	(0.1)%	(2.2)%
Valuation allowance	(25.1)%	(33.4)%	187.2 %
Chilean shareholder benefit due to tax regime change	0.4 %	(3.6)%	— %
Change in tax rate due to change in Chilean tax regime	— %	(6.2)%	— %
Other	(0.7)%	0.1 %	3.1 %
ARRA Section 1603 grant-basis reduction deferred tax assets	— %	— %	(223.7)%
Effective income tax rate	(9.8)%	(8.6)%	31.1 %

The following table presents significant components of the Company's deferred tax assets and deferred tax liabilities as follows (in thousands):

	Year ended December 31, 2015	2014
Deferred tax assets / (liabilities) — current:		
Accruals, prepaids and other deferred tax assets and liabilities	$—	$(344)
Basis difference in derivatives	—	4,779
Total gross deferred tax assets / (liabilities) — current	—	4,435
Less: valuation allowance	—	(4,266)
Total net deferred tax assets / (liabilities) — current	$—	$169
Deferred tax assets/(liabilities) — non-current:[1]		
Accruals, prepaids and other deferred tax assets and liabilities	$1,525	$—
Basis difference in derivatives	3,187	—
Property, plant and equipment	(175,527)	(104,767)
Basis difference in foreign subsidiaries	104	37,626
Partnership interest	34,664	994
Hatchet Ridge financing	27,096	28,044
Asset retirement obligation	4,970	5,216
Unrealized loss on derivatives	305	—
Other temporary differences	—	256
Other deferred tax assets and liabilities	(7,125)	(5,081)
Net operating loss carryforwards	224,194	130,248
Tax credits	4,421	—
Total gross deferred tax assets/(liabilities) — non-current[1]	$117,814	$92,536
Less: valuation allowance	(133,193)	(107,480)
Total net deferred tax assets / (liabilities) — non-current[1]	$(15,379)	$(14,944)
Total net deferred tax assets/(liabilities) [1]	$(15,379)	$(14,775)

(1) Presented in accordance with prospective adoption of ASU 2015-17, "Income Taxes: Balance Sheet Classification of Deferred Taxes." See Note 2, Summary of Significant Accounting Policies-Recently Issued Accounting Standards, for additional information.

The deferred tax assets and deferred tax liabilities resulted primarily from temporary differences between book and tax basis of assets and liabilities. The Company regularly assesses the likelihood that future taxable income levels will be sufficient to ultimately realize the tax benefits of the deferred tax assets. Should the Company determine that future realization of the tax benefits is not more likely than not, additional valuation allowance would be established which would increase the Company's tax provision in the period of such determination. The net deferred tax assets and net deferred tax liabilities as of December 31, 2015 and 2014 are attributed primarily to the Company's Canadian, Puerto Rican and Chilean entities. The net change in valuation allowance increased by $21.4 million and $11.8 million during the years ended December 31, 2015 and 2014, respectively.

As of December 31, 2015, the Company had U.S federal and state net operating loss ("NOLs") carryforwards in the amount of $503.6 million and $66.0 million, respectively, which begin to expire in the year ending December 31, 2032 for federal and state purposes.

Internal Revenue Code Section 382 places a limitation (the "Section 382 Limitation") on the amount of taxable income that can be offset by NOL and credit carryforwards, as well as built-in loss items, after a change in control (generally greater than 50% change in ownership) of a loss corporation. California has similar rules. The Company did not have any historic U.S. NOLs prior to October 2, 2013 except for NOLs from its Puerto Rico entity which may be subject to Section 382 Limitation.

The Company experienced a change in ownership on May 14, 2014. As a result, the Company's NOL carryforwards and credits generated through the date of change are subject to an annual limitation under Section 382. Accordingly, if the Company generates sufficient taxable income, the NOL carryforwards or credits prior to the change in ownership are not expected to expire.

The Company is required to recognize in the financial statements the impact of a tax position, if that position is more likely than not of being sustained on audit, based on the technical merits of the position. As of December 31, 2015, the Company does not have any unrecognized tax benefits and does not have any tax positions for which it is reasonably possible that the amount of gross unrecognized tax benefits will increase or decrease within 12 months after the year ended December 31, 2015.

The Company files income tax returns in the U.S. federal jurisdiction, various state jurisdictions and foreign jurisdictions for its Canadian, Chilean and Puerto Rican operations. The Company’s U.S. and foreign income tax returns for 2010 to 2015 are subject to examination.

The Company has a policy to classify accrued interest and penalties associated with uncertain tax positions together with the related liability, and the expenses incurred related to such accruals are included in the provision for income taxes. The Company did not incur any interest expenses or penalties associated with unrecognized tax benefits for the years ended December 31, 2015, 2014 and 2013.

The Company operates under a tax holiday in Puerto Rico which enacted a special tax rate of 4% for businesses dedicated to the production of energy for consumption through the use of renewal sources. Act 73 of May 28, 2008, as amended, known as the "Economic Incentives for the Development of Puerto Rico Act" (the "Act"), promotes the development of green energy projects through economic incentives to reduce the island’s dependency on oil. The Act provides for a 4% flat income tax rate on green energy income ("GEI") in lieu of any income tax imposed by the Puerto Rico Code for a 15 year period and is scheduled to terminate on December 31, 2026. The impact of the tax holiday decreased foreign deferred tax expense by $0.4 million for 2015. The impact of the tax holiday on basic and diluted net income (loss) per Class A common share was $0.005.

15. Stockholders' Equity

Initial Public Offering and Contribution Transactions

On October 2, 2013, the Company issued 16,000,000 shares of Class A common stock in an initial public offering generating net proceeds of approximately $317.0 million. Concurrent with the initial public offering, the Company issued 19,445,000 shares of Class A common stock and 15,555,000 shares of Class B common stock to Pattern Development and utilized approximately $232.6 million of the net proceeds of the initial public offering as additional consideration to Pattern Development for certain entities and assets contributed to the Company ("Contribution Transactions") consisting of interests in eight wind power projects, including six projects in operation (Gulf Wind, Hatchet Ridge, St. Joseph, Spring Valley, Santa Isabel and Ocotillo), and two projects that were under construction (El Arrayán and South Kent) at the time of the initial public offering. In accordance with ASC 805-50-30-5, Transactions between Entities under Common Control, the Company recognized the assets and liabilities contributed by Pattern Development at their historical carrying amounts at the date of the Contribution Transactions. On October 8, 2013, the Company’s underwriters exercised in full their overallotment option to purchase 2,400,000 shares of Class A common stock from Pattern Development, the selling stockholder, pursuant to the overallotment option granted by Pattern Development.

In connection with the Contribution Transactions, Pattern Development retained a 40% interest in Gulf Wind previously held by it such that, at the completion of the IPO, the Company, Pattern Development and the joint venture partner held interests of approximately 40%, 27% and 33%, respectively, of the distributable cash flow of Gulf Wind, together with certain allocated tax items. In July 2015, the Company acquired the noncontrolling interests of Gulf Wind. Refer to the Noncontrolling Interests discussion below, for additional information.

Preferred Stock

The Company has 100,000,000 shares of authorized preferred stock issuable in one or more series. The Company’s Board of Directors is authorized to determine the designation, powers, preferences and relative, participating, optional or other special rights of any such series. As of December 31, 2015 and 2014, there was no preferred stock issued and outstanding.

Common Stock

On July 28, 2015, the Company completed an underwritten public offering of its Class A common stock. In total, 5,435,000 shares of the Company's Class A common stock were sold. Net proceeds generated for the Company were approximately $120.8 million after deduction of underwriting discounts, commissions and transaction expenses.

On February 9, 2015, the Company completed an underwritten public offering of its Class A common stock. In total, 12,000,000 shares of the Company’s Class A common stock were sold. Of this amount, the Company issued and sold 7,000,000 shares of its

Class A common stock and Pattern Development, the selling stockholder, sold 5,000,000 shares of Class A common stock. The Company received net proceeds of approximately $196.2 million after deducting underwriting discounts and commissions and estimated offering expenses payable by the Company. The Company did not receive any proceeds from the sale of shares sold by Pattern Development.
On May 14, 2014, the Company completed an underwritten public offering of its Class A common stock resulting in a reduction of Pattern Development’s interest in the Company from approximately 63% to 35%. Consequently, the Company is no longer subject to ASC 805-50-30-5, Transactions between Entities under Common Control. All transactions with Pattern Development after May 14, 2014 are recognized at fair value on the measurement date in accordance with the ASC 805, Business Combinations. On February 9, 2015, the Company completed an underwritten public offering of its Class A common stock, resulting in a further reduction of Pattern Development’s interest in the Company from 35% to 25% causing it to no longer be entitled to certain approval rights pursuant to the Shareholder Approval Rights Agreement dated October 2, 2013.
Below is a summary of the rights and preferences of the Company’s Class A common stock as of December 31, 2015 and also the Company's Class B common stock as of December 31, 2014. The Company’s Class B common stock converted on a one-to-one basis into Class A common stock on December 31, 2014. As a result, the shares of Class B common stock were retired and the Company is no longer authorized to issue shares of Class B common stock.
Voting Rights
Holders of the Company’s Class A common stock are entitled to one vote per share on all matters submitted to a vote of stockholders and will vote as a single class under all circumstances, unless otherwise required by law. On February 9, 2015, Pattern Development's interest in the Company was reduced to 25% causing it to no longer be eligible to certain approval rights pursuant to Shareholder Approval Rights Agreement.
Dividend Rights
Holders of Class A common stock are eligible to receive dividends on common stock held when funds are available and as approved by the Board of Directors.

	Dividends Per Share	Declaration Date	Record Date	Payment Date
2015:				
Fourth Quarter	$0.3720	October 29, 2015	December 31, 2015	January 29, 2016
Third Quarter	$0.3630	July 21, 2015	September 30, 2015	October 30, 2015
Second Quarter	$0.3520	April 20, 2015	June 30, 2015	July 30, 2015
First Quarter	$0.3420	February 24, 2015	March 31, 2015	April 30, 2015

Liquidation Rights
In the event of any liquidation, dissolution or winding-up of the Company, holders of Class A common stock will be entitled to share ratably in the Company’s assets that remain after payment or provision for payment of all of its debts and obligations and after liquidation payments to holders of outstanding shares of preferred stock, if any.
Conversion
Upon the later of December 31, 2014 and the date on which the South Kent project achieves commercial operation ("Conversion Event"), all of the outstanding Class B common stock automatically converted, on a one-for-one basis, into Class A shares. There were no other conversion rights attached to Class B common stock. The Company’s South Kent project achieved commercial operation on March 28, 2014 and, as a result, the Company’s Class B common stock converted into Class A common stock on December 31, 2014.
Class B Common Stock—Beneficial Conversion Feature
The contingency on the conversion of the Class B common stock was removed when the South Kent project achieved commercial operation on March 28, 2014. The removal of this contingency resulted in the recognition of a beneficial conversion feature in the Company’s additional paid-in capital account. The beneficial conversion feature represented the intrinsic value of the conversion feature, which was measured as the difference between the fair value of Class B

common stock and the fair value of Class A common stock, into which the Class B common stock was convertible, as of October 2, 2013, which was the date of the Company's initial public offering. The beneficial conversion feature was accreted on a straight-line basis from March 28, 2014 through December 31, 2014 into the Company's additional paid-in capital account in the consolidated statements of stockholders' equity, as there were no available retained earnings.

Noncontrolling Interests

The following table presents the balances for noncontrolling interests by project and the Company's respective ownership percentage (in thousands, except percentages). See Note 3, Acquisitions, for additional information.

	December 31,		Noncontrolling Ownership Percentage December 31,	
	2015	2014	2015	2014
Gulf Wind	$—	$97,061	— %	60 %
El Arrayán	34,224	35,624	30 %	30 %
Logan's Gap	190,397	—	18 %	N/A
Panhandle 1	195,791	205,333	21 %	21 %
Panhandle 2	184,773	192,568	19 %	19 %
Post Rock	196,346	—	40 %	N/A
Amazon Wind Farm Fowler Ridge	142,731	—	35 %	N/A
Noncontrolling interest	$944,262	$530,586		

The following table presents the components of total noncontrolling interest as reported in stockholders' equity in the consolidated balance sheets by project (in thousands). See Note 3, Acquisitions, for additional information.

	Capital	Accumulated Income (Loss)	Accumulated Other Comprehensive Loss	Noncontrolling Interest
Balances at December 31, 2013	$90,217	$18,601	$(9,024)	$99,794
Contribution from noncontrolling interests	406,163	—	—	406,163
Fair value of noncontrolling interest in El Arrayán	35,259	—	—	35,259
Distribution to noncontrolling interests	(2,100)	—	—	(2,100)
Net loss	—	(8,709)	—	(8,709)
Other comprehensive income, net of tax	—	—	179	179
Balances at December 31, 2014	529,539	9,892	(8,845)	530,586
Acquisition of Post Rock	205,100	—	—	205,100
Buyout of noncontrolling interests	(88,747)	(14,244)	7,944	(95,047)
Contributions from noncontrolling interests	334,231	—	—	334,231
Distributions to noncontrolling interests	(7,882)	—	—	(7,882)
Net loss	—	(23,074)	—	(23,074)
Other comprehensive income, net of tax	—	—	348	348
Balances at December 31, 2015	$972,241	$(27,426)	$(553)	$944,262

16. Equity Incentive Award Plan

In September 2013, the Company adopted the 2013 Equity Incentive Award Plan ("2013 Plan"), which permits the Company to issue 3,000,000 aggregate number of Class A common shares for equity awards including incentive and nonqualified stock options, restricted stock awards ("RSAs") and restricted stock units ("RSUs") to employees, directors and consultants. RSAs provide the holder with immediate voting rights, but are restricted in all other respects until released. RSUs generally entitle the holders the right to receive the underlying shares of the Company's common stock upon vesting. Upon cessation of services to the Company, any nonvested RSAs and RSUs will be canceled. All nonvested RSAs and RSUs accrue dividends and distributions, which are subject to vesting and paid in cash upon release. Accrued dividends and distributions are forfeitable to the extent that the underlying awards do not vest. During 2015, the Company granted 186,136 RSAs to certain employees and 22,772 RSUs to certain directors. As of December 31, 2015, 2,083,734 aggregate number of Class A shares were available for issuance under the 2013 Plan.

Stock-Based Compensation

Stock-based compensation expenses related to stock options, RSAs, and RSUs are recorded as a component of general and administrative expenses in the Company's consolidated statements of operations and totaled $4.5 million, $4.1 million and $0.5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Stock Options

The Company did not grant stock option awards under the 2013 Plan during the years ended December 31, 2015 and 2014. For the year ended December 31, 2013, the fair value of employee stock options was estimated using the Black-Scholes option pricing model. The following weighted average assumptions were used:

	Year Ended December 31, 2013
Risk-free interest rate	1.68%
Expected life (in years)	5.8
Expected volatility	36%
Expected dividend yield	5.7%

The following table summarizes stock option activity under the 2013 Plan for the year ended December 31, 2015:

	Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value	
Outstanding at December 31, 2014	429,962	$ 22.00			
Exercised	—	22.00			
Forfeited or expired	—	22.00			
Outstanding at December 31, 2015	429,962	$ 22.00	7.8	$—	(1)
Exercisable at December 31, 2015	318,670	$ 22.00	7.8	$—	(1)
Vested and expected to vest, net of estimated forfeitures at December 31, 2015	429,962	$ 22.00	7.8	$—	(1)

(1) Closing stock price on December 31, 2015 is lower than the stock option exercise price.

The weighted-average grant-date fair value per stock option granted during the year ended December 31, 2013 was $4.11. During the year ended December 31, 2014, the Company issued 14,861 shares as a result of employee stock option exercises and cash received on exercise was $0.3 million. The total intrinsic value of stock options exercised was $0.1 million for the year ended December 31, 2014. Intrinsic value is defined as the amount by which the fair value of the underlying stock exceeds the exercise price at the time of stock option exercise. No stock options were exercised during each of the years ended December 31, 2015 and 2013.

As of December 31, 2015, the total unrecorded stock-based compensation expense, net of estimated forfeitures, related to nonvested stock options was $0.5 million, which is expected to be amortized over a weighted-average period of 0.8 years.

Restricted Stock Awards

The Company measures the fair value of time-based RSAs at the grant date and accounts for stock-based compensation by amortizing the fair value on a straight line basis over the related vesting period.

The following table summarizes RSA activity under the 2013 Plan for the year ended December 31, 2015:

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2014	118,015	$ 25.29
Granted	100,868	$ 29.58
Vested	(65,189)	$ 26.23
Forfeited	—	N/A
Repurchased for employee tax withholding	(30,826)	$ 27.67
Nonvested at December 31, 2015	122,868	$ 27.71

For the years ended December 31, 2015, 2014 and 2013, the total fair value of RSAs vested was $1.7 million, $2.2 million and $0.2 million, respectively. The weighted-average grant date fair values per RSA granted during the same periods were $29.58, $27.63 and $22.71, respectively.

As of December 31, 2015, the total unrecorded stock-based compensation expense for nonvested RSAs was $3.3 million, which is expected to be amortized over a weighted-average period of 1.5 years.

RSAs that contain Market Conditions

On April 10, 2015, the Company granted 85,268 restricted stock awards ("TSR-RSAs") to certain senior management personnel. These TSR-RSAs vest between 0% and 150% of the "Target" (56,844) at the later of a three-year performance period (January 1, 2015 - December 31, 2017), or the end of the requisite service period, which shall be no later than March 15, 2018, in accordance with the level of total shareholder return of the Company's stock price achieved relative to a peer group during the specified period. Following the date of grant, rights to dividends will accrue on the maximum number of shares and may be forfeited if the market or service conditions are not achieved. The Company measures the fair value of these restricted stock awards at the grant date using a Monte Carlo simulation model and amortizes the fair value over the longer of the requisite period or performance period. The Company estimates expected volatility based on the actual volatility of the Company's daily closing share price since listing on September 27, 2013 and the historical volatility of comparable publicly traded companies for a period that is equal to the performance period. The risk-free interest rate is based on the yield on U.S. government bonds for a period commensurate with the performance period. The initial TSR performance was measured using actual historical TSR performance of the Company and of comparable publicly traded companies over the period January 1, 2015 to April 9, 2015.

The following table summarizes TSR-RSAs activity under the 2013 Plan for the year ended December 31, 2015:

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2014	—	N/A
Granted	85,268	$39.16
Vested	—	N/A
Forfeited	—	N/A
Repurchased for employee tax withholding	—	N/A
Nonvested at December 31, 2015	85,268	$39.16

The weighted-average grant-date fair value of our TSR-RSAs granted was $39.16 per share during the year ended December 31, 2015.

As of December 31, 2015, the total unrecorded stock-based compensation expense related to nonvested TSR-RSAs was $1.7 million, which is expected to be amortized over a weighted-average period of 2.2 years.

RSAs that contain Performance Conditions

During the year ended December 31, 2014, the Company recorded compensation expense of $0.6 million related to RSAs, granted in March 2014, that were released to senior management personnel when certain performance conditions were met. These awards included 27,717 shares of restricted stock, with a weighted average grant date fair value of $27.03 that were released upon the Company achieving its cash available for distribution target as of December 31, 2014. On December 31, 2014, the performance condition was met.

As of December 31, 2015, there were no nonvested RSAs that contain performance conditions.

Restricted Stock Units

On January 2, 2015, the Company granted time-based deferred RSUs to certain directors. Deferred RSUs are equity awards that entitle the holder the right to receive shares of the Company's common stock upon vesting and are settled on, or as soon as administratively possible after, the settlement date which is January 1 following the date of the director's termination of service. The Company measures the fair value of deferred RSUs at the grant date and accounts for stock-based compensation by amortizing the fair value on a straight line basis over the related vesting period.

The following table summarizes RSU activity under the 2013 Plan for the year ended December 31, 2015:

	Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2014	—	N/A
Granted	22,772	$25.94
Vested	(22,772)	$25.94
Forfeited	—	N/A
Repurchased for employee tax withholding	—	N/A
Nonvested at December 31, 2015	—	N/A

For the year ended December 31, 2015, the total fair value of deferred RSUs vested was $0.6 million. The weighted-average grant date fair value of stock awards granted during the same period was $25.94. As of December 31, 2015, there were no nonvested deferred RSUs.

17. Loss Per Share

The Company computes loss per share attributable to common stockholders using the two-class method as the Company has outstanding shares that meet the definition of participating securities. The two-class method is used to determine net income (loss) per share for each class of common stock and participating securities according to dividends declared or accumulated in undistributed earnings. The two-class method requires income available to common stockholders for the period to be allocated between common and participating securities based on their respective rights to receive dividends as if all income for the period has been distributed.

The Company computes basic loss per share by dividing net income (loss) attributable to common stockholders (adjusted by net income (loss) allocated to participating securities) by the weighted-average number of shares outstanding for the period. Diluted net income (loss) attributable to common stockholders is adjusted to reallocate undistributed earnings based on the potential impact of dilutive securities (i.e. convertible senior notes). Diluted loss per share is computed by dividing diluted net income (loss) attributable to common stockholders by the weighted-average number of shares outstanding for the period, adjusted for the inclusion of potentially dilutive common shares assuming the dilutive effect of stock options, RSAs, RSUs and convertible senior notes.

The Company's deferred RSUs are deemed to be participating securities upon vesting, prior to release, as the vested units entitle each holder to nonforfeitable dividend rights. The Company's Class B common stock, which was converted to Class A common stock on a one-to-one basis on December 31, 2014 were deemed to be participating securities as Class B common stock holders had the same rights, including voting and liquidation rights, as Class A common stockholders, except with respect to net income and dividends as

Class B common stockholders were not entitled to distributions. Class B common stock had deemed dividends which represented the accretion of the beneficial conversion feature.

Potentially dilutive securities are determined by applying the treasury stock method to the assumed exercise of in-the-money stock options and the assumed vesting of outstanding RSAs and release of RSUs. Potentially dilutive securities related to convertible senior notes are determined using the if-converted method.

For the years ended December 31, 2015, 2014 and 2013, the Company excluded 3.5 million, 15.6 million and 15.6 million, respectively, of potentially dilutive securities from the diluted EPS calculation as their effect is anti-dilutive.

The computations for Class A basic and diluted loss per share are as follows (in thousands except share data):

	Year ended December 31,		
	2015	2014	2013
Numerator for basic and diluted loss per share:			
Net loss attributable to Pattern Energy	$(32,533)	$(31,290)	$(13,336)
Less: dividends declared on Class A common shares	(102,861)	(56,976)	(11,103)
Less: deemed dividends on Class B common shares	—	(21,901)	—
Less: earnings allocated to participating securities	(32)	—	—
Undistributed loss attributable to common stockholders	$(135,426)	$(110,167)	$(24,439)
Denominator for loss per share:			
Weighted average number of shares:			
Class A common stock - basic and diluted	70,535,568	42,361,959	35,448,056
Class B common stock - basic and diluted	—	15,555,000	15,555,000
Calculation of basic and diluted earnings (loss) per share:			
Class A common stock:			
Dividends	$1.46	$1.34	$0.31
Undistributed loss	(1.92)	(1.90)	(0.48)
Basic loss per share	$(0.46)	$(0.56)	$(0.17)
Class A common stock:			
Diluted loss per share	$(0.46)	$(0.56)	$(0.17)
Class B common stock:			
Deemed dividends	$—	$1.41	$—
Undistributed loss	—	(1.90)	(0.48)
Basic and diluted loss per share	$—	$(0.49)	$(0.48)
Dividends declared per Class A common share	$1.43	$1.30	$0.31
Deemed dividends per Class B common share	$—	$1.41	$—

18. Commitments and Contingencies

Commitments

The following table summarizes estimates of future commitments related to the various agreements that the Company has entered into (in thousands):

	2016	2017	2018	2019	2020	Thereafter	Total
Purchase, construction and other commitments	$20,661	$1,419	$563	$554	$591	$5,605	$29,393
Operating leases	11,103	12,069	14,156	14,637	14,811	285,977	352,753
Service and maintenance agreements	56,802	51,668	40,936	34,149	31,556	146,981	362,092
Total commitments	$88,566	$65,156	$55,655	$49,340	$46,958	$438,563	$744,238

Purchase, Construction and Other Commitments

The Company has entered into various commitments with service providers related to the Company's projects and operations of its business. Outstanding commitments include those related to construction, purchases of wind turbine spare parts from a third party contractor under a parts and service agreement, and commitments related to donations to local community and government organizations.

In accordance with the Company's acquisition of the membership interests in Amazon Wind Farm Fowler Ridge as referenced in Note 3, Acquisitions - Asset Acquisition - Amazon Wind Farm Fowler Ridge, the Company acquired an agreement between Pattern Development and an unrelated third party, whereby the unrelated third party is entitled to 1% of the gross revenue received by the project under the PPA which is effective in January 2016 and is estimated to be approximately $2.5 million over 13 years.

Operating Leases

The Company has entered into various long-term operating lease agreements related to lands for its wind farms. For the years ended December 31, 2015, 2014 and 2013, the Company recorded rent expenses of $12.0 million, $8.8 million and $6.1 million, respectively, in project expense in its consolidated statements of operations.

On February 3, 2016, the Company entered into a lease agreement for office facilities in Houston, Texas, effective July 2016, to replace the Pattern Development-leased office facilities which expires in June 2016. Total future commitments are included in operating leases in the table above. See Note 21, Subsequent Events, for additional information.

Effective January 1, 2016, Pattern Development assigned to the Company, all of Pattern Development's rights, title, commitments and interest under an office lease, dated as of September 9, 2009, with respect office space in San Francisco. As a result of this lease assignment, the Company assumed remaining rental commitments under the lease plus certain annual operating expense reimbursements and customary security deposits. Concurrently with the lease assignment, the Company entered into an extension through 2026 of the office lease, which previously terminated at the end of February 2017. Total future commitments are included in operating leases in the table above. See Note 21, Subsequent Events, for additional information.

Service and Maintenance Agreements

The Company has entered into service and maintenance agreements with third party contractors to provide turbine operations and maintenance services and modifications and upgrades for varying periods over the next 19 years. The computation of outstanding commitments includes an estimated annual price adjustment for inflation of 2%, where applicable.

Letters of Credit

Power Sale Agreements

The Company owns and operates wind power projects, and has entered into various long-term PSAs that terminate from 2019 to 2039. The terms of these agreements generally provide for the annual delivery of a minimum amount of electricity at fixed prices and in some cases include price escalation over the term of the agreement. Under the terms of these agreements, as of December 31, 2015,

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the Company issued irrevocable letters of credits to guarantee its performance for the duration of the agreements totaling $229.2 million.

Project Finance Agreements

The Company has various project finance agreements which obligate the Company to provide certain reserves to enhance its credit worthiness and facilitate the availability of credit. As of December 31, 2015, the Company issued irrevocable letters of credit totaling $108.1 million to ensure performance under these various project finance agreements.

Contingencies

Turbine Operating Warranties and Service Guarantees

The Company has various turbine availability warranties from its turbine manufacturers. Pursuant to these warranties, if a turbine operates at less than minimum availability during the warranty period, the turbine manufacturer is obligated to pay, as liquidated damages, an amount for each percent that the turbine operates below the minimum availability threshold. In addition, if a turbine operates at more than a specified availability during the warranty period, the Company has an obligation to pay a bonus to the turbine manufacturer. As of December 31, 2015, the Company recorded liabilities of $0.8 million associated with bonuses payable to the turbine manufacturers.

The Company also has service guarantees from its turbine service and maintenance providers. These service guarantees, primarily from one provider, are associated with long-term turbine service arrangements which commenced on various dates in 2014 and 2015 for certain wind projects. Pursuant to these guarantees, if a turbine operates at less than minimum availability during the guarantee period, the service provider is obligated to pay, as liquidated damages, an amount for each percent that the turbine operates below the minimum availability threshold. In addition, pursuant to certain of these guarantees, if a turbine operates at more than a specified availability during the guarantee period, the Company has an obligation to pay a bonus to the service provider. As of December 31, 2015, the Company recorded liability of $1.4 million associated with bonuses payable to service providers.

Legal Matters

From time to time, the Company has become involved in claims and legal matters arising in the ordinary course of business. Management is not currently aware of any matters that will have a material adverse effect on the financial position, results of operations, or cash flows of the Company.

Indemnity

The Company provides a variety of indemnities in the ordinary course of business to contractual counterparties and to its lenders and other financial partners. The Company is party to certain indemnities for the benefit of project finance lenders and tax equity partners of certain projects. These consist principally of indemnities that protect the project finance lenders from, among other things, the potential effect of any recapture by the U.S. Department of the Treasury of any amount of the Cash Grants previously received by the projects and eligibility of production tax credits and certain legal matters, limited to the amount of certain related costs and expenses.

19. Related Party Transactions

From inception to October 1, 2013, the Company's project management and administrative activities were provided by Pattern Development. Costs associated with these activities were allocated to the Company and recorded in its consolidated statements of operations. Allocated costs include cash and non-cash compensation, other direct, general and administrative costs, and non-operating costs deemed allocable to the Company. Measurement of allocated costs is based principally on time devoted to the Company by officers and employees of Pattern Development. The Company believes the allocated costs presented in its consolidated statements of operations are a reasonable estimate of actual costs incurred to operate the business. The allocated costs are not the result of arms-length, free-market dealings.

Management Services Agreement and Shared Management

Effective October 2, 2013, the Company entered into a bilateral Management Services Agreement with Pattern Development which provides for the Company and Pattern Development to benefit, primarily on a cost-reimbursement basis plus a 5% fee on certain direct costs, from the parties' respective management and other professional, technical and administrative personnel, all of whom report to the Company’s executive officers. Pursuant to the Management Services Agreement, certain of the Company’s executive officers, including its Chief Executive Officer, "shared PEG executives." also serve as executive officers of Pattern Development and devote their time to both the Company and Pattern Development as is prudent in carrying out their executive responsibilities and fiduciary duties. The shared PEG executives have responsibilities for both the Company and Pattern Development and, as a result, these individuals do not devote all of their time to the Company's business. Under the terms of the Management Services Agreement, Pattern Development is required to reimburse the Company for an allocation of the compensation paid to such shared PEG executives reflecting the percentage of time spent providing services to Pattern Development.

The following table presents net bilateral management service cost reimbursements included in the consolidated statements of operations (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Project expense	$—	$—	$1,995
Related party general and administrative	7,589	5,787	$8,169
Related party income	(2,665)	(2,612)	$(665)
Other (expense) income, net	—	—	$(551)
Total	$4,924	$3,175	$8,948

As of December 31, 2015 and 2014, the net amounts payable to Pattern Development for bilateral management service cost reimbursements were $1.6 million and $0.8 million, respectively. In addition, the Company recorded a receivable of $0.1 million and $0.1 million for the years ended December 31, 2015 and 2014, respectively, related to expense reimbursements due from Pattern Development.

Purchase and Sales Agreements

On December 20, 2013, the Company acquired a 45% interest in Grand from Pattern Development. Subject to the terms of the agreement, the Company was required to make a potential contingent payment of up to C$5.0 million. In September 2015, the Company settled the contingent obligation and made a payment of C$2.4 million, or $1.8 million calculated based on the September 2015 average exchange rate, as calculated based on final budget to actual amounts and distributions payable to Pattern Development upon term conversion.

On July 28, 2015, the Company acquired a 27% interest in the Gulf Wind project from Pattern Development for a cash purchase price of approximately $13.0 million. See Note 15, Stockholders' Equity - Noncontrolling Interests, for additional information.

On June 17, 2015, the Company acquired a one-third equity interest in K2 from Pattern Development for a purchase price of approximately $128.4 million, plus assumed proportionate debt of approximately $221.8 million, U.S. dollar equivalent. In November 2015, upon term conversion, an additional $4.0 million of contingent consideration became due payable to the seller, resulting in an adjusted purchase price of approximately $132.4 million. This represents a 90 MW interest in the 270 MW wind project, located in the Township of Ashfield-Colborne-Wawanosh, Ontario.

On April 29, 2015, the Company acquired 100% of the membership interests in Fowler Ridge IV Wind Farm LLC through the acquisition of Fowler Ridge IV B Member LLC from Pattern Development for a purchase price of approximately $37.5 million, paid at closing, plus $0.6 million of capitalized transaction expenses. On December 18, 2015, pursuant to the Purchase and Sale Agreement between the Company and Pattern Development, the Company settled a contingent obligation and made a payment of $27.2 million upon tax equity funding. Amazon Wind Farm Fowler Ridge is a 150 MW wind project located in Benton County, Indiana.

On December 19, 2014, the Company acquired 100% of the membership interests in Logan's Gap from Pattern Development, for a purchase price of approximately $15.1 million, and an assumed liability to a third-party. Logan's Gap is a 164 MW wind project located in Comanche County, Texas.

On November 10, 2014, the Company completed its acquisition of 100% of the Class B membership interest in the Panhandle 2 wind project, representing a 81% initial ownership interest in the project's distributable cash flow, through the acquisition of Panhandle B Member 2 LLC, from Pattern Development, for a purchase price of approximately $123.8 million, which includes debt assumed of $195.4 million that was repaid immediately after acquisition. This represents a 147 MW interest in the 182 MW wind project, located in Carson County, Texas.

On June 30, 2014, the Company acquired 100% of the Class B membership interest in the Panhandle 1 wind project, representing a 79% initial ownership interest in the project’s distributable cash flow, through the acquisition of Panhandle Wind Holdings LLC, from Pattern Development, for a purchase price of approximately $124.4 million. This represents a 172 MW interest in the 218 MW wind project, located in Carson County, Texas.
On June 25, 2014, the Company acquired a 100% equity interest in AEI El Arrayán, an entity holding a 38.5% indirect interest in El Arrayán, for a total purchase price of approximately $45.3 million. The Company owned a 31.5% indirect interest in El Arrayán prior to acquiring the additional 38.5% interest in order to obtain majority control, or 70% interest, in the project. El Arrayán is a 115 MW wind power project, located in Ovalle, Chile.
Management fees
The Company provides management services and receives a fee for such services under agreements with its joint venture investees, South Kent, Grand, K2 and El Arrayán, prior to the AEI EL Arrayán acquisition on June 25, 2014, in addition to various Pattern Development subsidiaries. Management fees of $3.6 million, $3.3 million and $0.9 million were recorded as related party revenue in the consolidated statements of operations for the years ended December 31, 2015, 2014, and 2013, respectively, and a related party receivable of $0.6 million and $0.7 million was recorded in the consolidated balance sheets as of December 31, 2015 and 2014, respectively.
Employee Savings Plan
The Company participates in a 401(k) plan sponsored and maintained by Pattern Development, established on August 3, 2009 and restated on October 3, 2013. The Company also sponsors a Canadian Registered Retirement Savings Plan ("RRSP"), established on October 2, 2013. Participants in the plans are allowed to defer a portion of their compensation, not to exceed the respective Internal Revenue Service or Canada Revenue Agency annual allowance contribution guidelines, and are 100% vested in their respective deferrals and earnings. Participants may choose from a variety of investment options. The Company contributes 5% of base compensation to each employee’s 401(k) or RRSP account, up to the annual compensation limit. For the years ended December 31, 2015, 2014 and 2013, the Company contributed $0.5 million, $0.3 million and $0.1 million, respectively, which was recorded in the consolidated statements of operations as either general and administrative expense or cost of revenue.

20. Selected Quarterly Financial Data (Unaudited)
The following tables summarize the Company’s unaudited quarterly consolidated statements of operations for each of the eight quarters in the two year period ended December 31, 2015. The quarterly consolidated statements of operations data were prepared on a basis consistent with the audited consolidated financial statements included in this Annual Report on Form 10-K.
Quarterly financial data in thousands, except per share data:

	Three months ended			
	December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
Revenue	$90,597	$89,697	$84,671	$64,866
Gross profit	$16,674	$22,250	$22,348	$10,564
Net (loss) income	$(3,873)	$(35,332)	$5,657	$(22,059)
Net loss attributable to noncontrolling interest	$(6,327)	$(5,927)	$(8,660)	$(2,160)
Net income (loss) attributable to Pattern Energy	$2,454	$(29,405)	$14,317	$(19,899)
Basic and diluted earnings (loss) per share—Class A common stock	$0.03	$(0.40)	$0.21	$(0.30)
Cash dividends declared per Class A common share	$0.37	$0.36	$0.35	$0.34

	Three months ended December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
Revenue	$79,418	$71,519	$65,007	$49,549
Gross profit	$26,311	$17,669	$27,023	$12,298
Net (loss) income	$(15,986)	$(9,281)	$7,167	$(21,899)
Net income (loss) attributable to noncontrolling interest	$4,406	$(2,073)	$(4,032)	$(7,010)
Net (loss) income attributable to Pattern Energy	$(20,392)	$(7,208)	$11,199	$(14,889)
Basic (loss) earnings per share—Class A common stock	$(0.36)	$(0.15)	$0.17	$(0.20)
Diluted (loss) earnings per share—Class A common stock	$(0.36)	$(0.15)	$0.16	$(0.29)
Basic and diluted (loss) earnings per share—Class B	$(0.23)	$(0.02)	$0.28	$(0.51)
Cash dividends declared per Class A common share	$0.34	$0.33	$0.32	$0.31
Deemed dividends per Class B common share	$0.46	$0.46	$0.48	$—

21. Subsequent Events

On February 24, 2016, the Company approved an increased dividend for the first quarter 2016, payable on April 29, 2016, to holders of record on March 31, 2016, in the amount of $0.3810 per Class A share, which represents $1.524 on an annualized basis. This represents a 2.4% increase from the fourth quarter 2015 dividend of $0.3720.

On February 3, 2016, the Company entered into a lease agreement for office facilities in Houston, Texas, effective July 2016, to replace the Pattern Development-leased office facilities which expires in June 2016. Total future rental commitments under this lease agreement is approximately $14.1 million, including certain annual operating expense reimbursements. The new lease agreement expires in February 2027.

Effective January 1, 2016, Pattern Development assigned to the Company, all of Pattern Development’s rights, title, commitments and interest under an office lease, dated as of September 9, 2009, with respect to office space in San Francisco. As a result of this lease assignment, the Company assumed remaining rental commitments under the lease plus certain annual operating expense reimbursements and customary security deposits. Concurrently with the lease assignment, the Company entered into an extension through 2026 of the office lease, which previously terminated at the end of February 2017. Total future commitments assumed under the extended lease agreement are approximately $38.7 million, plus certain annual operating expense reimbursements.

Schedule I—Condensed Parent-Company Financial Statements
Pattern Energy Group Inc.
Condensed Financial Information of Parent
Balance Sheets
(In thousands of U.S. dollars, except share data)

	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$26,938	$34,772
Related party receivable	3,050	1,982
Derivative assets, current	3,482	—
Current net deferred tax assets	—	307
Prepaid expenses	487	514
Other current assets	381	3,970
Total current assets	34,338	41,545
Restricted cash	250	—
Investments in subsidiaries	918,270	586,641
Investments in affiliates	116,473	29,079
Derivative assets	628	—
Net deferred tax assets	—	147
Other assets	—	85
Total assets	$1,069,959	$657,497
Liabilities and equity		
Current liabilities:		
Accounts payable and other accrued liabilities	$7,590	$6,404
Related party payable	1,643	757
Accrued interest	3,842	—
Dividend payable	28,022	15,734
Current deferred tax liabilities	—	147
Total current liabilities	41,097	23,042
Convertible senior notes, net of financing costs of $5,014 and $0 as of December 31, 2015 and 2014, respectively	197,362	—
Net deferred tax liabilities	—	307
Total liabilities	238,459	23,349
Equity:		
Class A common stock, $0.01 par value per share: 500,000,000 shares authorized; 74,644,141 and 62,062,841 shares outstanding as of December 31, 2015 and 2014, respectively	747	621
Additional paid-in capital	955,254	696,378
Capital	—	—
Accumulated loss	(49,599)	(17,066)
Accumulated other comprehensive loss	(73,325)	(45,068)
Treasury stock, at cost; 65,301 and 25,465 shares of Class A common stock as of December 31, 2015 and 2014, respectively	(1,577)	(717)
Total equity	831,500	634,148

Total liabilities and equity	$1,069,959	$657,497

See accompanying notes to parent company financial statements

Pattern Energy Group Inc.
Condensed Financial Information of Parent
Statements of Operations and Comprehensive Income (Loss)
(In thousands of U.S. dollars)

	Year ended December 31,		
	2015	2014	2013
Revenue	$—	$—	$—
Expenses	29,483	23,089	3,630
Operating loss	(29,483)	(23,089)	(3,630)
Other income (expense):			
Interest expense	(6,107)	—	—
Equity in (losses) earnings from subsidiaries	(19,058)	18,064	12,641
Equity in earnings (losses) from affiliates	16,119	(25,295)	7,846
Gain on undesignated derivatives	5,107	—	—
Related party income	2,665	2,612	665
Other expenses, net	(1,558)	(3,566)	(563)
Other (expense) income	(2,832)	(8,185)	20,589
Net (loss) income before income tax	(32,315)	(31,274)	16,959
Tax provision	218	16	—
Net (loss) income	(32,533)	(31,290)	16,959
Other comprehensive (loss) income:			
Proportionate share of subsidiaries' other comprehensive (loss) income, net of tax benefit of $1,206, $514 and $0, respectively	(16,085)	(30,724)	23,478
Proportionate share of affiliates' other comprehensive (loss) income activity, net of tax benefit (provision) of $1,524, $1,855 and ($615), respectively	(4,228)	(5,991)	2,473
Total other comprehensive (loss) income, net of tax	(20,313)	(36,715)	25,951
Comprehensive (loss) income	$(52,846)	$(68,005)	$42,910

See accompanying notes to parent company financial statements

Pattern Energy Group Inc.
Condensed Financial Information of Parent
Condensed Statements of Cash Flows
(In thousands of U.S. dollars)

	Year ended December 31, 2015	2014	2013
Operating activities			
Net (loss) income	$(32,533)	$(31,290)	$16,959
Adjustments to reconcile net (loss) income to net cash used in operating activities:			
Amortization of financing costs	472	—	—
Amortization of debt discount	1,794	—	—
Gain on derivatives	(4,110)	—	—
Stock-based compensation	4,462	4,105	511
Net loss on transactions	—	1,473	—
Equity in losses (earnings) from subsidiaries	19,058	(18,064)	(12,641)
Equity in (earnings) losses from affiliates	(16,119)	25,295	(7,846)
Changes in operating assets and liabilities:			
Prepaid expenses	35	(93)	(428)
Other current assets	43	(3,452)	(18)
Accounts payable and other accrued liabilities	473	1,999	93
Related party receivable/payable	(183)	(639)	(1,007)
Accrued interest payable	3,842	—	—
Net cash used in operating activities	(22,766)	(20,666)	(4,377)
Investing activities			
Cash paid for acquisitions, net of cash acquired	(65,042)	—	—
Distribution from subsidiaries	(613,089)	108,581	233,226
Contribution to subsidiaries	244,969	(362,533)	(172,130)
Increase in restricted cash	(250)	—	—
Net cash (used in) provided by investing activities	(433,412)	(253,952)	61,096
Financing activities			
Proceeds from public offering, net of expenses	317,432	286,757	317,926
Proceeds from issuance of convertible senior notes, net of issuance costs	218,929	—	—
Proceeds from exercise of stock options	—	327	—
Refund for deposit for letters of credit	3,425	—	—
Repurchase of shares for employee tax withholding	(860)	(693)	(24)
Capital contributions - Pattern Development	—	—	32,678
Capital distributions - Pattern Development	—	—	(98,884)
Capital distributions - Contribution Transactions	—	—	(232,640)
Dividends paid	(90,582)	(52,344)	—
Payment for deferred equity issuance costs	—	(433)	—
Net cash provided by financing activities	448,344	233,614	19,056
Net change in cash and cash equivalents	(7,834)	(41,004)	75,775
Cash and cash equivalents at beginning of period	34,772	75,776	1
Cash and cash equivalents at end of period	$26,938	$34,772	$75,776
Supplemental disclosures			
Cash payments for income taxes	$218	$16	$—
	$(433)	$—	$—

Equity issuance costs paid in prior period related to current period offerings			
Schedule of non-cash activities			
Non-cash increase in additional paid-in capital from buyout of noncontrolling interests	$16,715	$—	$—
See accompanying notes to parent company financial statements			

Pattern Energy Group Inc.
Note to Parent Company Financial Statements

Supplemental Notes

1. Summary of Significant Accounting Policies

Basis of Presentation

The condensed, standalone, financial statements of Pattern Energy Group Inc. ("parent company") have been presented in accordance with Rule 12-04, Schedule I of Regulation S-X as the restricted net assets of the subsidiaries of the parent company exceed 25% of the consolidated net assets of the parent company and its subsidiaries. The condensed parent company financial statements have been prepared in accordance with United States generally accepted accounting principles ("U.S. GAAP") and should be read in conjunction with the parent company's consolidated financial statements and the accompanying notes thereto.

Investments

For purposes of these financial statements, the parent company's wholly owned and majority owned subsidiaries are recorded based on its proportionate share of the subsidiaries' assets. The parent company's share of net income of its unconsolidated subsidiaries is included in income using the equity method.

South Kent Wind LP
Financial Statements
December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

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South Kent Wind LP

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February 16, 2016

Independent auditor's report

To the Partners of
South Kent Wind LP

We have audited the accompanying balance sheets of South Kent Wind LP as of December 31, 2015 and 2014 and the related statement of operations and comprehensive income (loss), changes in partners' equity, and cash flows for each of the years in the three-year period ended December 31, 2015. Management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We were not engaged to perform an audit of the company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of South Kent Wind LP as of December 31, 2015 and 2014 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, South Kent Wind LP retrospectively changed its method of balance sheet classification of deferred financing costs due to the adoption of ASU 2015-03, Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs in 2015.

/s/ PricewaterhouseCoopers LLP
Chartered Professional Accountants, Licensed Public Accountants

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"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

South Kent Wind LP
Balance Sheets
As of December 31, 2015 and 2014
(In thousands of Canadian Dollars)

	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$23,363	$16,427
Restricted cash (note 3)	6,558	3,087
Accrued revenue (note 2)	18,167	15,963
Other current assets	448	615
Total current assets	48,536	36,092
Restricted cash (note 3)	—	10,930
Property, plant and equipment - net of accumulated depreciation of $57,634 and $28,272 in 2015 and 2014, respectively (note 4)	679,183	709,826
Intangible assets - net of accumulated amortization of $727 and $684 in 2015 and 2014, respectively (note 5)	711	754
Total assets	$728,430	$757,602
LIABILITIES & EQUITY		
Current liabilities:		
Accounts payable and other accrued liabilities	$6,220	$3,759
Accounts payable and other accrued liabilities - related parties (note 11)	190	2,141
Current portion of long-term debt, net of financing costs of $3,546 and $2,916 in 2015 and 2014, respectively (notes 2 and 6)	18,564	20,269
Current portion of long-term contingent liabilities (note 10)	1,021	500
Derivative liabilities, current (note 8)	12,835	10,008
Total current liabilities	38,830	36,677
Long-term debt, net of financing costs of $14,817 and $13,705 in 2015 and 2014, respectively (notes 2 and 6)	626,897	645,012
Long-term contingent liabilities, net of current (note 10)	8,500	12,586
Derivative liabilities (note 8)	38,707	23,107
Asset retirement obligation (note 7)	5,829	6,550
Total liabilities	718,763	723,932
Commitments and contingencies (note 10)		
Equity:		
Partners' capital	2,700	53,412
Accumulated net income (loss)	6,967	(19,742)
Total partners' equity	9,667	33,670
Total liabilities and equity	$728,430	$757,602

See accompanying notes to financial statements.

South Kent Wind LP
Statements of Operations and Comprehensive Income (Loss)
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	2015	2014	2013
Revenue (note 2):			
Energy delivered	$102,076	$72,633	$—
Compensation for forgone energy	22,345	10,749	—
Other revenue	2,981	1,597	—
Total revenue	127,402	84,979	—
Cost of revenue:			
Project expenses	13,232	9,715	—
Project expenses - related parties (note 11)	1,446	1,075	—
Depreciation, amortization and accretion	29,710	28,493	33
Total cost of revenue	44,388	39,283	33
Gross profit	83,014	45,696	(33)
Operating expenses:			
General and administrative	929	756	661
General and administrative - related parties (note 11)	507	463	556
Total operating expenses	1,436	1,219	1,217
Operating income (loss)	81,578	44,477	(1,250)
Other income (expense):			
Interest expense (note 6)	(35,342)	(29,133)	(583)
Unrealized (loss) gain on derivatives (note 8)	(18,428)	(52,057)	18,942
Other (expense) income, net	(1,099)	(290)	86
Total other (expense) income	(54,869)	(81,480)	18,445
Net income (loss)	26,709	(37,003)	17,195
Other comprehensive income	—	—	—
Comprehensive income (loss)	$26,709	$(37,003)	$17,195

See accompanying notes to financial statements.

South Kent Wind LP
Statements of Changes in Partners’ Equity
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	Partners’ capital	Accumulated net income (loss)	Total
Balance at January 1, 2013	$35,440	$66	$35,506
Cash contribution	9,016	0	9,016
Cash distribution	(21,393)	0	(21,393)
Non-cash contribution	80,101	0	80,101
Net income	0	17,195	17,195
Balance at December 31, 2013	103,164	17,261	120,425
Cash distribution	(49,752)	0	(49,752)
Net loss	0	(37,003)	(37,003)
Balance at December 31, 2014	53,412	(19,742)	33,670
Cash distribution	(50,712)	0	(50,712)
Net income	0	26,709	26,709
Balance at December 31, 2015	$2,700	$6,967	$9,667

See accompanying notes to financial statements.

South Kent Wind LP
Statements of Cash Flows
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$26,709	$(37,003)	$17,195
Adjustment to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Unrealized loss (gain) on derivatives	18,428	52,057	(18,942)
Depreciation, amortization and accretion	29,710	28,493	100
Amortization of deferred financing costs	3,388	2,184	—
Bad debt expense	—	—	300
Interest expense added on principal	—	8,092	—
Changes in assets and liabilities, net:			
Accrued revenue	(2,204)	(15,963)	—
Accounts payable and other accrued liabilities	(2,555)	3,628	—
Other, net	168	724	—
Net cash provided by (used in) operating activities	73,644	42,212	(1,347)
Cash flows from investing activities:			
Capital expenditures	(247)	(113,235)	(480,400)
Decrease in restricted cash	59,013	84,363	—
Increase in restricted cash	(51,554)	(71,492)	(21,488)
Net cash provided by (used in) investing activities	7,212	(100,364)	(501,888)
Cash flows from financing activities:			
Proceeds from long-term debt	5,106	126,106	535,754
Repayment of long-term debt	(23,185)	(1,914)	—
Deferred financing costs paid	(5,129)	—	(20,418)
Proceeds from partners' contributions	—	—	9,016
Distribution to partners	(50,712)	(49,752)	(21,393)
Net cash (used in) provided by financing activities	(73,920)	74,440	502,959
Net increase (decrease) in cash and cash equivalents	6,936	16,288	(276)
Cash and cash equivalents - Beginning of year	16,427	139	415
Cash and cash equivalents - End of year	$23,363	$16,427	$139
Supplemental disclosure:			
Cash payments for interest and commitment fees	$31,954	$17,422	$2,883
Schedule of non-cash activities:			
Remeasurement of asset retirement obligation	$1,027	$—	$—
Accrued construction costs	$	$3,586	$42,443
Non-monetary asset contribution from partners	$—	$—	$80,101
Construction loan - capitalized interest	$—	$4,987	$8,878
Capitalized depreciation and amortization	$—	$601	$1,201
Community fund commitment	$—	$—	$10,000

See accompanying notes to financial statements.

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1 General Information
The Partnership
South Kent Wind LP (the Partnership), a limited partnership under the laws of the Province of Ontario, was formed on January 10, 2011, as a joint venture project between Samsung Renewable Energy Inc. (Samsung) and Pattern South Kent LP Holdings LP, a subsidiary of Pattern Renewable Holdings Canada ULC (PRHC), each as 49.99% limited partners of the Partnership, and South Kent Wind GP Inc. (the GP), as the 0.02% general partner of the Partnership. The Partnership was created to develop, build and operate a wind power project in the Regional Municipality of Chatham-Kent with generation capacity totaling approximately 270 megawatts (MW) of power (the Project).
On February 24, 2013, Samsung transferred all of its LP interest in the Partnership to SRE SKW LP Holdings LP, an affiliate of Samsung.
On October 2, 2013, in a series of transactions: (i) Pattern South Kent GP Holdings Inc., a wholly owned subsidiary of PRHC, transferred all of the general partner interests in Pattern South Kent LP Holdings LP to PRHC, causing Pattern South Kent LP Holdings LP to be dissolved by operation of law and PRHC to acquire the LP interests in the Partnership that previously were held by Pattern South Kent LP Holdings LP; (ii) PRHC transferred its LP interest in the Partnership and its ownership interest in Pattern South Kent GP Holdings Inc., which owned PRHC's ownership interest in the GP, to Pattern Canada Operations Holdings ULC (PCOH), a wholly owned subsidiary of Pattern Energy Group Inc. (Pattern); and (iii) Pattern South Kent GP Holdings Inc. was dissolved.
On December 17, 2014, PCOH transferred all of its LP interest in the Partnership to Pattern Canada Finance Company ULC, a wholly owned subsidiary of PCOH.
The Partnership is controlled by its general partner, the GP, also a joint venture controlled by affiliates of Samsung and Pattern. As of December 31, 2015 and 2014, the Partnership's ownership interests were distributed as follows:

	2015		2014	
SRE SKW LP Holdings LP	49.99	%	49.99	%
Pattern Canada Finance Company ULC	49.99	%	49.99	%
South Kent Wind GP Inc.	0.02	%	0.02	%
Total	100.00	%	100.00	%

The Project
The Project is a 270 MW wind project consisting of 124 Siemens wind turbine generators located in the Regional Municipality of Chatham-Kent, Ontario. On August 2, 2011, the Partnership entered into a power purchase agreement (PPA) with the Independent Electricity System Operator (IESO) related to the sale of 100% of the electrical output of the Project at prescribed electricity rates for a period of 20 years following Commercial Operation Date (COD). On March 28, 2014, the Project achieved COD and commenced commercial operations.
2 Summary of significant accounting policies
The principal accounting policies applied in the preparation of these financial statements are set out below. These policies have been consistently applied to the periods presented, unless otherwise stated.
Basis of preparation
The accompanying financial statements are presented using accounting principles generally accepted in the United States of America (U.S. GAAP). The preparation of U.S. GAAP financial statements requires management to make certain estimates and assumptions

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that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Because the use of estimates is inherent in the financial reporting process, actual results could differ from those estimates.

In recording transactions and balances resulting from business operations, the Partnership uses estimates based on the best information available. Estimates are used for such items as accrued revenue, asset retirement obligation, valuation of derivative contracts and acquisition of contingencies.

These financial statements do not include assets, liabilities, revenue and expenses of the GP and limited partners. The financial statements of the Partnership reflect no provision or liability for income taxes because profits and losses of the Partnership are allocated to the partners and are included in the income tax returns of the partners. Income and losses for tax purposes may differ from the financial statement amounts and the partners' equity reflected in the financial statements does not necessarily reflect their tax basis.

Change in depreciable life of property, plant and equipment

The Partnership periodically reviews the estimated economic useful lives of its fixed assets. This review indicated that the expected economic useful life of the power plant was longer than the estimated economic useful life used for depreciation purposes in the Partnership's financial statements. As a result, effective January 1, 2015, the Partnership changed its estimate of the economic useful life of the power plant from 20 to 25 years and updated the calculation of asset retirement obligation to reflect the change. For the year ended December 31, 2015, the effect of this change reduced depreciation expense and accretion expense by $7,605 and $57, respectively and increased net income by $7,662.

Functional and presentation currency

Items included in the financial statements of the Partnership are measured using the currency of the primary economic environment in which the Partnership operates (the functional currency). The financial statements are presented in Canadian Dollars, which is the Partnership's functional and presentation currency.

Fair value of financial instruments

ASC 820, Fair Value Measurements, defines fair value as the price at which an asset could be exchanged or a liability transferred in an orderly transaction between knowledgeable, willing parties in the principal or most advantageous market for the asset or liability. Where available, fair value is based on observable market prices or derived from such prices. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

Restricted cash

Restricted cash mainly consists of cash reserves required under the Partnership's loan agreements and security deposits required to collateralize commercial bank letter of credit facilities related primarily to interconnect rights and a power purchase agreement (PPA) (note 3).

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Trade receivable
The Partnership's trade receivables are generated by selling energy in Ontario, Canada, and allowance for doubtful accounts, if needed, is computed based upon management's estimates of uncollectible accounts. As of December 31, 2015 and 2014, the Partnership has no outstanding trade receivables.
Accrued revenue
Accrued revenue represents revenues recognized on contracts for which billings have not been presented to customers as of the balance sheet date. These amounts are billed and generally collected within two months.
Concentration of credit risk and significant customer
Financial instruments that potentially subject the Partnership to concentrations of credit risk consist primarily of cash and cash equivalents and restricted cash. The Partnership places its cash and cash equivalents and restricted cash with creditworthy institutions located in Canada, which the management believes to have minimal risk. At times, such balances may be in excess of the Canada Deposit Insurance Corporation (CDIC) insurance coverage limit. CDIC insurance currently covers up to $100 per depositor at each insured bank.
The IESO is the only customer of the Partnership, which is obligated to pay for 100% of the electrical output under a long-term, fixed priced PPA. There are no accounts receivable that are past due.
The Partnership's derivative agreements expose the Partnership to losses under certain circumstances, such as the counterparty defaulting on its obligations under the swap agreements or if the swap agreements provide an imperfect hedge. Counterparties to the Partnership's derivative contracts are major financial institutions that have been accorded investment grade ratings.
Property, plant and equipment
Property, plant and equipment are stated at historical cost, less accumulated depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Subsequent costs are included in the asset's carrying value or recognized as separate assets, as appropriate, only when it is probable that the future economic benefits associated with the item will flow to the Partnership and the cost of the item can be reliably measured.
The asset retirement obligation included in property, plant and equipment is stated at the present value of future cash flows of asset retirement obligation at the time of COD.
Depreciation on property, plant and equipment is calculated using the straight-line method to allocate their cost to their residual values over their estimated useful life. The power plant is depreciated over 25 years and the remaining assets are depreciated over 5 years. The assets' residual values and useful lives are reviewed and adjusted, if appropriate, at the end of each reporting period. Repair and maintenance costs are expensed as incurred.
Intangible assets (lease options)
Lease options are recognized at fair value at the acquisition date and subsequently accounted for at cost. Lease options have a finite useful life and are carried at cost less accumulated amortization. Amortization is calculated using the straight-line method to allocate the cost of lease options over the period of expected future benefit (i.e., the contract period of each lease option). Separately acquired lease options are capitalized on the basis of the costs incurred to enter into the respective contract.
Impairment of long-lived assets
The Partnership periodically evaluates whether events have occurred that would require revision of the remaining useful life of equipment and improvements and purchased intangible assets or render them not recoverable. If such circumstances arise, the Partnership uses an estimate of the undiscounted value of expected future operating cash flows to determine whether the long-lived

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assets are impaired. If the aggregate undiscounted cash flows are less than the carrying amount of the assets, the resulting impairment charge to be recorded is calculated based on the excess of the carrying value of the assets over the fair value of such assets, with the fair value determined based on an estimate of discounted future cash flows. Through December 31, 2015, no impairment charges were recorded.

Deferred financing costs

Financing costs incurred in connection with obtaining construction and term financing, which include direct financing, legal and other upfront costs of borrowing, are capitalized and recorded as a reduction to long-term debt and amortized over the lives of the respective loans using the effective-interest method. Amortization of deferred financing costs is capitalized during construction or expensed following COD.

Interest capitalization

The Partnership capitalizes interest and related financing fees from non-recourse debt used to finance projects in construction. Capitalization is discontinued when a project reaches commercial operation.

Derivatives

The Partnership recognizes its derivative instruments as either assets or liabilities in the balance sheets at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it qualifies and has been designated as part of a hedging relationship and, further, on the type of hedging relationship. For derivative instruments that are designated and qualify as a cash flow hedge (i.e., hedging the exposure to variability in expected future cash flows that are attributable to a particular risk), the effective portion of the gain or loss on the derivative instrument is reported as a component of other comprehensive income (OCI). Changes in the fair value of these derivatives are subsequently reclassified into earnings in the period the hedged transaction affects earnings. The ineffective portion of changes in fair value is recorded as a component of net income (loss) in the statements of operations and comprehensive income (loss).

For undesignated derivative instruments, their change in fair value is reported as a component of net income (loss) in the statements of operations and comprehensive income (loss).

The Partnership enters into derivative transactions for the purpose of managing exposure to fluctuations in interest rates, such as interest rate swaps. Interest rate swaps are instruments used to fix the interest rate on variable interest rate debt.

Accounts payable and other accrued liabilities

Trade payables are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers. Payables with payment terms extended beyond one year from the balance sheet dates are presented as non-current liabilities.

Contingent liabilities

Contingent liabilities are recognized when: the Partnership has a present legal obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and the amount has been reasonably estimated.

Asset retirement obligation

The Partnership records an asset retirement obligation for the estimated costs of decommissioning turbines, removing above-ground installations and restoring sites, at the time when a contractual decommissioning obligation materializes. The Partnership records accretion expense, which represents the increase in the asset retirement obligation, over the remaining life of the associated wind project. Accretion expense is recorded as cost of revenue in the statements of operations and comprehensive income (loss) using accretion rates based on a credit adjusted risk free interest rate of 5.54%.

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Revenue recognition
The Partnership sells the electricity it generates under the terms of a PPA with the IESO. Revenue is recognized based upon the amount of electricity delivered or curtailed at rates specified under the contracts, assuming all other revenue recognition criteria are met. The Partnership evaluates its PPA to determine whether it is in substance a lease or derivative and, if applicable, recognizes revenue pursuant to ASC 840 Leases and ASC 815 Derivatives and Hedging, respectively. As of December 31, 2015, the PPA was not accounted for as a lease or derivative and revenue was recognized on an accrual basis.
The Partnership recognizes revenue under other revenue for warranty settlements and liquidated damages from a turbine manufacturer upon resolution of outstanding contingencies and for economic development adder from the IESO based on the amount of energy delivered. Any cash receipts for amounts subject to future adjustment or repayment are deferred in other liabilities until the final settlement amount is considered fixed and determinable.
Cost of revenue
The Partnership's cost of revenue is comprised of direct costs of operating and maintaining its project facilities, including labor, turbine service arrangements, metering service and shadow settlement, environmental fee, land lease royalties, property tax, insurance, depreciation, amortization and accretion.
Comprehensive income
Comprehensive income consists of net income and other comprehensive income. Other comprehensive income is included in accumulated other comprehensive income in the accompanying statements of changes in partners' equity.
Reclassification
Certain prior period balances have been reclassified to conform to current period presentation of the Partnership's financial statements and accompanying notes. Such reclassifications did not have an impact on net income (loss) or cash flows.
Recent accounting pronouncement
In April 2015, the Financial Accounting Standard Board (FASB) issued ASU 2015-03, “Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs” to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. ASU 2015-03 is effective for public companies for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years and should be applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. Upon transition, an entity is required to comply with the applicable disclosures for a change in accounting principle. The Partnership adopted ASU 2015-03 in April 2015 and applied the change in accounting principle to the financial statements as of December 31, 2015. As a result, the Partnership reclassified $18,363 and $16,621 in total deferred financing costs to long-term debt, of which $3,546 and $2,916 have been reclassified to current portion of long-term debt, as of December 31, 2015 and December 31, 2014, respectively, on the Partnership's balance sheets. The adoption of ASU 2015-3 had no impact on the Partnership's results of operations and cash flows.
New standards, amendments and interpretations were issued but not effective for the financial period ended December 31, 2015 and were not early adopted. The Partnership intends to adopt these standards, if applicable, when they become effective.
In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers: Deferral of the Effective Date” to amend ASU 2015-09 “Revenue from Contracts with Customers” to defer the effective date of ASU 2014-09 for all entities by one year. The guidance in ASU 2014-09 provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including

industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. As a result of this

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amendment, ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted only as of annual reporting periods beginning after December 15, 2015 and interim periods within those fiscal years. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption, through a cumulative adjustment. In June 2015, the FASB voted to defer the effective date by one year, with early adoption permitted as of the original effective date. The Partnership is currently assessing the future impact of this update on its financial statements and related disclosures and expects to adopt this update beginning January 1, 2018.
In June 2015, the FASB issued ASU 2015-10, “Technical Corrections and Improvements” which covers a wide range of topics in the Accounting Standards Codification (the “Codification”). The amendments in this update represent changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost on most entities. The amendments in ASU 2015-10 were effective immediately upon issuance and the adoption did not have material impact on the Partnership's financial statements and related disclosures.
3 Restricted cash
The following table presents the components of restricted cash:

	December 31,	
	2015	2014
Completion reserve account	$2,210	$6,614
Siemens incentive reserve account	4,316	4,316
Security deposit for letter of guarantee	25	2,639
10% holdback account for contractors	—	448
Distribution account	7	—
Subtotal	6,558	14,017
Less: current portion	(6,558)	(3,087)
Restricted cash, non-current	$—	$10,930

The amount in the completion reserve account is reserved to pay outstanding project costs specified during term conversion (note 6). Upon full payment of outstanding project costs, the remaining balance will be released from restricted cash.
The amount in the Siemens incentive account is reserved to pay operational incentive payments to Siemens if it is confirmed in early 2016 that the Siemens Three-Year Employment Objective was achieved by December 31, 2015 (note 10).

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4 Property, plant and equipment

The following is a summary of property, plant and equipment, at cost less accumulated depreciation, at December 31:

	December 31, 2015	2014
Power plant	$731,053	$731,307
Furniture, fixtures and equipment	501	501
Asset retirement obligation - asset	5,263	6,290
Subtotal	736,817	738,098
Less: Accumulated depreciation	(57,634)	(28,272)
	$679,183	$709,826

Depreciation expense of $29,361, $28,185, and $33 was charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively.

5 Intangible assets

	December 31, 2015	2014
Beginning net book value	$754	$431
Additions	—	415
Amortization expense	(43)	(92)
Closing net book value	$711	$754

	December 31, 2015	2014
Cost	$1,438	$1,438
Accumulated amortization	(727)	(684)
Net book value	$711	$754

Amortization expense of $43, $48, and $0 was charged to the statements of operations and comprehensive income for the years ended December 31, 2015, 2014 and 2013, respectively and $0 and $44 was capitalized to property, plant and equipment on the balance sheets as of December 31, 2015 and 2014, respectively.

6 Long-term debt

On March 8, 2013, the Partnership entered into a credit agreement with a group of lenders for a $683,817 construction facility that was convertible to a term loan upon achievement of the COD, letter of credit facility and an interest rate hedge facility for a term of construction period plus seven years at a rate of Canadian Dealer Offered Rate (CDOR) plus 2.5% per annum for the first four years and CDOR plus 2.75% per annum thereafter. The funds from these facilities were utilized to finance the construction of the Project and to run the Project’s operations. The Partnership achieved COD on March 28, 2014, and the construction facility converted to a term loan on August 28, 2014.

In connection with the credit agreement, the Partnership entered into interest rate swaps that would fix the interest rate for 90% of the outstanding notional amount.

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On May 7, 2015, the Partnership amended the credit agreement to reduce the related interest rate to Canadian Dealer Offered Rate (CDOR) plus 1.625% per annum. A fee facility was added with a principal amount of $5,106 to cover all fees for the amendment. The modifications have resulted in an effective interest rate of 2.505% to be applied to the carrying amount of the debt prospectively. Interest expense through the maturity date of August 2021 will be reduced accordingly.

Collateral under the financing agreement consists of substantially all of the Partnership's assets. Its loan agreement contains a broad range of covenants that, subject to certain exceptions, restrict the Partnership's ability to incur debt, grant liens, sell or lease assets, transfer equity interest, dissolve, pay distributions and change its business. The Partnership is in compliance with all loan covenants. All of the limited and general partners and shareholders of general partners pledged shares of partnership units or common stock owned as collateral for the loan.

Terms and conditions of outstanding borrowings were as follows:

	As of December 31, 2015				
	Principal	Deferred financing costs	Net of financing costs	Interest rate	Maturity date
Term loan	$663,824	$(18,363)	$645,461	2.505%	August 2021
Less:	(22,110)	3,546	(18,564)		
Net of current	$641,714	$(14,817)	$626,897		

	As of December 31, 2014				
	Principal	Deferred financing costs	Net of financing costs	Interest rate	Maturity date
Term loan	$681,902	$(16,621)	$665,281	3.78%	August 2021
Less: current portion	(23,185)	2,916	(20,269)		
Net of current	$658,717	$(13,705)	$645,012		

Future maturities of long-term debt are as follows as of December 31, 2015:

2016	$22,109
2017	25,773
2018	26,819
2019	28,144
2020	29,974
Thereafter	531,005
	$663,824

The following table presents a reconciliation of interest expense presented in the Partnerships' statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Interest incurred	$31,954	$31,450	$9,053
Commitment fees incurred	—	703	3,057
Amortization of deferred financing costs	3,388	2,741	1,056
Less: Capitalized interest, commitment and amortization	—	(5,761)	(12,583)
Interest expense	$35,342	$29,133	$583

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Revolving credit facility
On August 28, 2014, letters of credit of $40,600 and $12,000 were issued upon term conversion for debt service reserve and operations and maintenance reserve, respectively, with a seven-year term. Funds, when and if drawn on the facility, accrue interest at 0.625% plus Prime Rate, and at the partners' option, the rate can be converted to a rate of CDOR plus 1.625% per annum. In addition, the Partnership shall pay letter of credit fees on the basis of the undrawn amount of the facility at 1.625% per annum. As of December 31, 2015 and 2014, the letters of credit facility did not have an outstanding balance, and no amounts were drawn in 2015 and 2014. Letter of credit fees of $1,015 and $450 were charged to other expense in the statements of operations and comprehensive income (loss) for the years ended December 31, 2015 and 2014, respectively.

7 Asset retirement obligation

The Partnership's asset retirement obligation represents the estimated cost of decommissioning the turbines, removing above-ground installations and restoring the sites at the end of its estimated useful life. Effective January 1, 2015, the Partnership changed its estimate of the useful life of the power plant from 20 years to 25 years. As a result, during the year ended December 31, 2015, the Partnership recorded a one-time adjustment of $1,027 to reduce the carrying amount of the asset retirement obligations to reflect the change in estimate associated with the timing of the original undiscounted cash flows.
The following table presents a reconciliation of the beginning and ending aggregate carrying amounts of the asset retirement obligation:

	December 31,	
	2015	2014
Asset retirement obligation, beginning of year	$6,550	$5,833
Additions	—	457
Adjustment related to change in useful life	(1,027)	—
Accretion expense	306	260
Asset retirement obligation, end of year	$5,829	$6,550

8 Derivatives

The Partnership uses interest rate derivatives to manage its exposure to fluctuations in interest rates. Interest rate risk exists primarily on variable-rate debt for which the cash flows vary based upon movement in market prices. The Partnership's objectives for holding these derivative instruments include reducing, eliminating and efficiently managing the economic impact of interest rate exposures as effectively as possible. The Partnership does not hedge all of its interest rate risks, thereby exposing the unhedged portions to changes in market prices.
As of December 31, 2015, the Partnership had other energy-related contracts that did not meet the definition of a derivative instrument and were therefore exempt from fair value accounting treatment.
The following tables present the fair values of the Partnership's derivative instruments on a gross basis as reflected on the Partnership's balance sheets:

	December 31, 2015		December 31, 2014	
	Derivative liabilities		Derivative liabilities	
	Current	Long-term	Current	Long-term
Fair value of undesignated derivatives:				
Interest rate swaps	$12,835	$38,707	$10,008	$23,107
Total fair value	$12,835	$38,707	$10,008	$23,107

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The following table summarizes the notional amounts of the Partnership's outstanding derivative instruments:

	Unit of measure	December 31 2015	2014
Undesignated derivative instruments			
Interest rate swaps	CAD	$592,846	$613,712

The changes in the fair value of these swaps are recognized directly into earnings as follows:

	December 31 2015	2014
Losses recognized in earnings	$(18,428)	$(52,057)

9 Fair value measurement

The Partnership’s fair value measurements incorporate various factors, including the credit standing and performance risk of the counterparties, the applicable exit market, and specific risks inherent in the instrument. Non-performance and credit risk adjustments on risk management instruments are based on current market inputs when available, such as credit default hedge spreads. When such information is not available, internal models are used.

Assets and liabilities recorded at fair value in the financial statements are categorized based on the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to valuation of these assets or liabilities are as follows:

Level 1 - Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 - Inputs (other than quoted prices included in Level 1) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument’s anticipated life.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities and which reflect management’s best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Short-term financial instruments consist principally of cash and cash equivalents, restricted cash, and accounts payable and other accrued liabilities. Based on the nature and short maturity of these instruments, their fair value is approximated using carrying cost and they are presented in the financial statements at carrying cost.

Long-term debt is presented on the balance sheets at amortized cost. The fair value of the Partnership’s long-term debt is approximately $663,824 and $681,902 as of December 31, 2015 and 2014, respectively. It is estimated based on current rates that would be available for debt of similar terms which is not significantly different from its stated value.

Derivatives are presented in the financial statements at fair value. The interest rate swaps were valued by discounting the net cash flows using the forward CDOR curve with the valuations adjusted by the Project’s credit default swap rate.

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The Partnership's financial assets (liabilities) which require fair value measurement on a recurring basis are classified within the fair value hierarchy as follows:

	Level 1	Level 2	Level 3
December 31, 2015			
Interest rate swaps	$—	$(51,542)	$—
December 31, 2014			
Interest rate swaps	$—	$(33,115)	$—

10 Commitments and contingencies

1) Commitments

Power Purchase Agreement

The Partnership entered into a PPA with the Ontario Power Authority on August 2, 2011, which subsequently merged with the IESO. The term of the PPA provides for the annual delivery of electricity at fixed prices with price escalation for 20% of the fixed price over the duration of the PPA, which is 20 years from COD.

Land Lease Agreements

The Partnership has entered into various long-term land lease agreements. The annual fees range from minimum rent payments varying by lease to maximum rent payments of a certain percentage of energy delivered revenues, varying by lease.

Lease payments, including amortization of the lease option, of $3,253, $2,433, and $0 were charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively, and $0 and $44 were capitalized to property, plant and equipment in the balance sheets as of December 31, 2015 and 2014 respectively.

The future payments related to these leases as of December 31, 2015 are as follows:

2016	$4,106
2017	4,119
2018	4,134
2019	4,152
2020	4,170
Thereafter	57,071
Total	$77,752

Service and Maintenance Agreement

The Partnership has entered into service and maintenance agreements with Siemens to provide and carry out turbine maintenance and service activities for the Project until April 2017. Based on the terms of the agreements, Siemens shall be entitled to receive a daily base fee per turbine that may be subject to periodic price adjustments for inflation, over the terms of the agreements. As of December 31, 2015, outstanding commitments with Siemens were $8,565, including an estimated annual price adjustment for inflation of 2%, where applicable, payable over the full term of the agreement.

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Operational Incentive Agreement
On March 8, 2013, an Operational Incentive Agreement was entered into between Samsung, an affiliate of PRHC and Siemens Canada Limited (Siemens) to define operational objectives and the terms and conditions upon which the Partnership may pay operational incentive payments to Siemens for achieving one or more of such operational objectives under the turbine supply agreements of certain projects under development by Samsung and affiliates of PRHC, including the Project. $3,586 was recorded as accrued liabilities which will be due to Siemens if it is confirmed in early 2016 that the Siemens Three-Year Employment Objective was achieved by December 31, 2015 (note 3).
The operational incentive payment shall not exceed any of the applicable maximums of (a) $0.02 per kW of the agreed de-rated capacity (270MWh) of wind turbines purchased under the TSA for the Project, and (b) an aggregate of $15,000 under all TSAs for all projects subject to the Operational Incentive Agreement, including the Project, and other affiliated wind projects.
2) Contingencies
Community Fund Agreement
On April 17, 2013, the GP, in its capacity as general partner and on behalf of the Partnership, entered into the South Kent Wind Community Fund Agreement with Chatham-Kent Community Foundation, in which the Partnership committed to twenty annual contributions of $500 plus an initial contribution of $1,000. In April 2013, the initial $1,000 was paid upon close of construction financing and capitalized to property, plant and equipment. The remaining payments were recorded as a contingent liability in the amount of $9,000.
Turbine Availability Warranty
The Partnership has a turbine availability warranty from its turbine manufacturer. Pursuant to the warranty, if a turbine operates at less than minimum availability during the warranty period, the turbine manufacturer is obligated to pay, as liquidated damages, an amount for each percent that the turbine operates below the minimum availability threshold. In addition, if a turbine operates at more than a specified availability during the warranty period, the Partnership has an obligation to pay a bonus to the turbine manufacturer. As of December 31, 2015, the Partnership recorded a liability of $521 associated with bonuses payable to the turbine manufacturer.
11 Related party transactions
The Partnership is controlled by the GP, which is jointly controlled by Samsung and Pattern in accordance with the terms of the Shareholder Agreement. Certain terms of the Samsung Pattern Joint Venture Wind Development Agreement, entered into between Samsung and an affiliate of PRHC on July 27, 2010, directed the responsibilities of Samsung and PRHC during the development of the Project.
The following transactions were carried out with related parties:
a.Management, Operation, and Maintenance Agreement (MOMA)
On March 8, 2013, the Partnership entered into a MOMA with Pattern Operators Canada ULC, which is owned by PCOH to operate and manage the maintenance of the wind plant and to perform certain other services pertaining to the wind plant in accordance with terms and conditions set forth in the MOMA.
The amounts of $0 and $214 were capitalized and recorded to property, plant and equipment in the balance sheets as of December 31, 2015 and 2014, respectively, and $1,446, $1,075 and $0 were charged to the project expense in the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively.

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b.Engineering Procurement and Construction Contract (EPC Contract)
On March 8, 2013, the Partnership entered into an EPC contract with SRE SKW EPC LP, which is 100% owned by Samsung, to build the balance of plant. $0, $29,122 and $184,067 have been invoiced to the Partnership for the years ended December 31, 2015, 2014 and 2013, respectively, which were capitalized and reclassed to property, plant and equipment in the balance sheets upon achievement of COD.
c.Project Administration Agreement (PAA)
On March 8, 2013, the Partnership entered into the PAA with SRE Wind PA LP (PA), which is 100% owned by Samsung to supply project administrative services.
$507, $463 and $556 were invoiced to the Partnership for the years ended December 31, 2015, 2014 and 2013, respectively, and expensed as general and administrative expense in the statements of operations and comprehensive income (loss).
d.The Partnership recorded the following balances with related parties:

	2015	2014
Related party payable to Pattern Operators Canada ULC	$142	$134
Related party payable to SRE Wind PA LP	$48	$1,960
Related party payable and accrued liabilities to SRE SKW EPC LP	$—	$47

12 Subsequent events
There were no material subsequent events.

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Grand Renewable Wind LP

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February 16, 2016

Independent auditor’s report

To the Partners of
Grand Renewable Wind LP

We have audited the accompanying balance sheets of Grand Renewable Wind LP as of December 31, 2015 and 2014 and the related statement of operations and comprehensive income (loss), changes in partners’ equity, and cash flows for each of the years in the three-year period ended December 31, 2015. Management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We were not engaged to perform an audit of the company’s internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company’s internal control over financial reporting. Accordingly, we express no such opinion. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Grand Renewable Wind LP as of December 31, 2015 and 2014 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, Grand Renewable Wind LP retrospectively changed its method of balance sheet classification of deferred financing costs due to the adoption of ASU 2015-03, Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs in 2015.

/s/ PricewaterhouseCoopers LLP
Chartered Professional Accountants, Licensed Public Accountants

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“PwC” refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Grand Renewable Wind LP
Balance Sheets
As of December 31, 2015 and 2014
(In thousands of Canadian Dollars)

	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$5,365	$2,596
Restricted cash (note 3)	3,461	6,228
Sales tax recoverable	—	6,586
Accrued revenue (note 2)	9,230	3,498
Other current assets	446	337
Total current assets	18,502	19,245
Restricted cash (note 3)	8,986	—
Property, plant and equipment - net of accumulated depreciation of $18,687 and $1,350 in 2015 and 2014, respectively (note 4)	414,214	414,068
Intangible assets - net of accumulated amortization of $91 and $7 in 2015 and 2014, respectively (note 5)	1,581	1,665
Total assets	$443,283	$434,978
LIABILITIES & EQUITY		
Current liabilities:		
Accounts payable and other accrued liabilities	$3,338	$18,335
Accounts payable and other accrued liabilities - related parties (note 11)	5,445	4,274
Current portion of long-term debt, net of financing costs of $1,597 and $1,627 in 2015 and 2014, respectively (notes 2 and 6)	12,300	7,545
Derivative liabilities, current (note 8)	8,643	7,040
Other current liabilities (note 10)	345	1,857
Total current liabilities	30,071	39,051
Long-term debt, net of financing costs of $6,707 and $8,270 in 2015 and 2014, respectively (notes 2 and 6)	362,606	332,141
Contingent liabilities (note 10)	—	1,976
Derivative liabilities (note 8)	45,887	38,059
Asset retirement obligation (note 7)	2,637	3,074
Total liabilities	441,201	414,301
Commitments and contingencies (note 10)		
Equity:		
Partners' capital	47,680	67,990
Accumulated net loss	(11,740)	(19,532)
Accumulated other comprehensive loss	(33,858)	(27,781)
Total partners' equity	2,082	20,677
Total liabilities and equity	$443,283	$434,978

See accompanying notes to financial statements.

Grand Renewable Wind LP
Statements of Operations and Comprehensive Income (Loss)
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	2015	2014	2013
Revenue (note 2):			
Energy delivered	$56,138	$3,429	$—
Compensation for forgone energy	5,227	—	—
Other revenue	1,046	62	—
Total revenue	62,411	3,491	—
Cost of revenue:			
Project expenses	8,179	4	—
Project expenses - related parties (note 11)	1,244	75	—
Depreciation, amortization and accretion	17,498	1,326	—
Total cost of revenue	26,921	1,405	—
Gross profit	35,490	2,086	—
Operating expenses:			
General and administrative	1,546	1,345	337
General and administrative - related parties (note 11)	406	288	433
Total operating expenses	1,952	1,633	770
Operating income (loss)	33,538	453	(770)
Other (expense) income:			
Interest expense (note 6)	(21,958)	(1,697)	(147)
Unrealized loss on derivatives (note 8)	(3,354)	(16,072)	(1,247)
Other (expense) income, net	(434)	(149)	61
Total other expense	(25,746)	(17,918)	(1,333)
Net income (loss)	7,792	(17,465)	(2,103)
Other comprehensive loss:			
Derivative activity (notes 8 and 10):			
Effective portion of change in fair value of derivatives	(14,397)	(18,934)	(8,847)
Reclassifications to net loss	8,320	—	—
Total change in effective portion of change in fair market value of derivatives	(6,077)	(18,934)	(8,847)
Comprehensive income (loss)	$1,715	$(36,399)	$(10,950)

See accompanying notes to financial statements.

Grand Renewable Wind LP
Statements of Changes in Partners' Equity
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	Partners' capital	Accumulated net income (loss)	Accumulated other comprehensive loss	Total
Balance at January 1, 2013	7,740	36	—	7,776
Cash contribution	32,410	—	—	32,410
Non-cash contribution	27,840	—	—	27,840
Other comprehensive loss	—	—	(8,847)	(8,847)
Net loss	—	(2,103)	—	(2,103)
Balance at December 31, 2013	67,990	(2,067)	(8,847)	57,076
Other comprehensive loss	—	—	(18,934)	(18,934)
Net loss	—	(17,465)	—	(17,465)
Balance at December 31, 2014	67,990	(19,532)	(27,781)	20,677
Cash distribution	(20,310)	—	—	(20,310)
Other comprehensive loss	—	—	(6,077)	(6,077)
Net income	—	7,792	—	7,792
Balance at December 31, 2015	$47,680	$(11,740)	$(33,858)	$2,082

See accompanying notes to financial statements.

Grand Renewable Wind LP
Statements of Cash Flows
For the years ended December 31, 2015, 2014 and 2013
(In thousands of Canadian Dollars)

	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$7,792	$(17,465)	$(2,103)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Unrealized loss on derivatives	3,354	16,072	1,247
Depreciation, amortization and accretion	17,582	1,332	—
Amortization of deferred financing costs	1,593	158	3
Interest expense added on principal	5,832	736	—
Changes in assets and liabilities, net:			
Accrued revenue	(5,732)	(3,498)	—
Sales tax recoverable	6,586	—	—
Accounts payable and other accrued liabilities	(15,460)	—	—
Other, net	(1,963)	482	—
Net cash provided by (used in) operating activities	19,584	(2,183)	(853)
Cash flows from investing activities:			
Capital expenditures	(18,082)	(209,808)	(95,359)
Net changes in accounts payable and other accrued liabilities related to investing activities	—	(48,624)	—
Decrease in restricted cash	28,352	13,456	—
Increase in restricted cash	(34,571)	(12,862)	(3,822)
Net cash used in investing activities	(24,301)	(257,838)	(99,181)
Cash flows from financing activities:			
Proceeds from long-term debt	39,968	258,230	82,367
Repayment of long-term debt	(12,172)	—	—
Deferred financing costs paid	—	—	(10,962)
Proceeds from partners' contributions	—	—	32,410
Distribution to partners	(20,310)	—	—
Net cash provided by financing activities	7,486	258,230	103,815
Net change in cash and cash equivalents	2,769	(1,791)	3,781
Cash and cash equivalents - Beginning of year	2,596	4,387	606
Cash and cash equivalents - End of year	$5,365	$2,596	$4,387
Supplemental disclosure:			
Cash payments for interest and commitment fees	$16,218	$—	$—
Schedule of non-cash activities:			
Remeasurement of asset retirement obligation	$598	$—	$—
Accrued construction costs	$—	$1,976	$17,142
Non-monetary asset contribution from partners	$—	$—	$27,840

Construction loan - capitalized interest	$—	$9,103	$510
Capitalized depreciation and amortization	$—	$870	$—
Effective portion of change in fair value of derivatives	$6,077	$18,934	$8,847

See accompanying notes to financial statements.

Grand Renewable Wind LP
Notes to Financial Statements
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1 General information

The Partnership

Grand Renewable Wind LP (the Partnership), a limited partnership under the laws of the Province of Ontario, was formed on January 10, 2011 as a joint venture project between Samsung Renewable Energy Inc. (Samsung) and Pattern Grand LP Holdings LP, a subsidiary of Pattern Renewable Holdings Canada ULC (PRHC), each as 49.99% limited partners of the Partnership, and Grand Renewable Wind GP Inc. (the GP), as the 0.02% general partner of the Partnership. The Partnership was created to develop, build and operate a wind power project in Haldimand County with generation capacity totaling approximately 149 megawatts (MW) of power (the Project).

On February 24, 2013, Samsung transferred its LP interest in the Partnership to SRE GRW LP Holdings LP, an affiliate of Samsung.

On December 20, 2013, in a series of transactions: (i) Pattern Grand GP Holdings Inc., a wholly owned subsidiary of PRHC, transferred all of the general partner interests in Pattern Grand LP Holdings LP to PRHC, causing Pattern Grand LP Holdings LP to be dissolved by operation of law and PRHC to acquire the LP interests in the Partnership that previously were held by Pattern Grand LP Holdings LP, (ii) PRHC transferred its LP interest in the Partnership and its ownership interest in Pattern Grand GP Holdings Inc., which owned PRHC’s ownership interest in the GP, to Pattern Canada Operations Holdings ULC, (PCOH), a wholly owned subsidiary of Pattern Energy Group Inc. (Pattern), and (iii) Pattern Grand GP Holdings Inc. was dissolved.

On December 17, 2014, PCOH transferred all of its LP interest in the Partnership to Pattern Canada Finance Company ULC, a wholly owned subsidiary of PCOH.

Six Nations agreements

On May 25, 2012, the Partnership entered into certain agreements with the Six Nations of the Grand River, a band within the meaning of the Indian Act (Canada) through its elected council (the Six Nations), in which the Partnership provides an option for economic participation by way of an annual royalty from the Partnership or the right to purchase a 10% interest in the Partnership.

On June 11, 2013, the Six Nations exercised its option to purchase a 10% LP interest in the Partnership and the Partnership Agreement was amended and restated to reflect such ownership. Affiliates of Samsung and Pattern each maintain a 45% interest in the Partnership. The Six Nations is not involved in the GP.

The Partnership is controlled by its general partner, the GP, also a joint venture controlled by affiliates of Samsung and Pattern. The Partnership’s ownership interests were distributed as follows:

	December 31,			
	2015		2014	
SRE GRW LP Holdings LP	44.99	%	44.99	%
Pattern Canada Finance Company ULC	44.99	%	44.99	%
Six Nations of the Grand River	10.00	%	10.00	%
Grand Renewable Wind GP Inc.	0.02	%	0.02	%
Total	100.00	%	100.00	%

The Project

The Project is a 149 MW wind project consisting of 67 Siemens wind turbine generators located in Haldimand County, Ontario.

On August 2, 2011, the Partnership entered into a power purchase agreement (PPA) with the Independent Electricity System Operator (IESO) related to the sale of 100% of the electrical output of the Project at prescribed electricity rates for a period of 20 years

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following Commercial Operation Date (COD). On December 9, 2014, the Project achieved COD and commenced commercial operations.

On July 13, 2015, the Project entered into settlement agreements with the EPC Contractor and prime sub-contractor, the project construction providers, which is a related party to a limited partner of the Partnership, to settle claims for cost increases and schedule relief in the construction of the Project asserted by the project construction providers against the Partnership and the third party owner of an adjacent 100 MW solar project that jointly owns transmission facilities with the Partnership that were constructed by the project construction providers, on the one hand, and claims asserted by the Partnership and the solar project owner against the project construction providers, on the other hand. The settlement agreements provide for a net payment by the Partnership of $14,300.

A 100 MW solar facility developed by an affiliate of Samsung is sharing the usage and ownership of the transmission line and substation. The Project connected to the IESO-controlled grid by way of a 20 km transmission line sited in the municipal road allowance.

2 Summary of significant accounting policies

The principal accounting policies applied in the preparation of these financial statements are set out below. These policies have been consistently applied to the periods presented, unless otherwise stated.

Basis of preparation

The accompanying financial statements are presented using accounting principles generally accepted in the United States of America (U.S. GAAP). The preparation of U.S. GAAP financial statements requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Because the use of estimates is inherent in the financial reporting process, actual results could differ from those estimates.

In recording transactions and balances resulting from business operations, the Partnership uses estimates based on the best information available. Estimates are used for such items as accrued revenue, asset retirement obligation, valuation of long-term derivative contracts and acquisition contingencies.

These financial statements do not include assets, liabilities, revenue and expenses of the GP and limited partners. The financial statements of the Partnership reflect no provision or liability for income taxes because profits and losses of the Partnership are allocated to the partners and are included in the income tax returns of the partners. Income and losses for tax purposes may differ from the financial statement amounts and the partners’ equity reflected in the financial statements does not necessarily reflect their tax basis.

Change in depreciable life of property, plant and equipment

The Partnership periodically reviews the estimated economic useful lives of its fixed assets. This review indicated that the expected economic useful life of the power plant were longer than the estimated economic useful life used for depreciation purposes in the Partnership’s financial statements. As a result, effective January 1, 2015, the Partnership changed its estimate of the economic useful life of the power plant from 20 to 25 years and updated the calculation of asset retirement obligation to reflect the change. For the year ended December 31, 2015, the effect of this change reduced depreciation expense and accretion expense by $4,371 and $39, respectively, and increased net income by $4,410.

Functional and presentation currency

Items included in the financial statements of the Partnership are measured using the currency of the primary economic environment in which the Partnership operates (the functional currency). The financial statements are presented in Canadian dollars, which is the Partnership’s functional and presentation currency.

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Fair value of financial instruments
ASC 820, Fair Value Measurements, defines fair value as the price at which an asset could be exchanged or a liability transferred in an orderly transaction between knowledgeable, willing parties in the principal or most advantageous market for the asset or liability. Where available, fair value is based on observable market prices or derived from such prices. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments' complexity.
Cash and cash equivalents
Cash and cash equivalents include cash on hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.
Restricted cash
Restricted cash mainly consists of cash reserves required under the Partnership's loan agreements and security deposits required to collateralize commercial bank letter of credit facilities related primarily to interconnect rights and a power purchase agreement (PPA) (note 3).
Trade receivables
The Partnership's trade receivables are generated by selling energy in Ontario, Canada, and allowance for doubtful accounts, if needed, is computed based upon management's estimates of uncollectible accounts. As of December 31, 2015 and 2014, the Partnership has no outstanding trade receivables.
Accrued revenue
Accrued revenue represents revenues recognized on contracts for which billings have not been presented to customers as of the balance sheet date. These amounts are billed and generally collected within two months.
Concentration of credit risk and significant customer
Financial instruments that potentially subject the Partnership to concentrations of credit risk consist primarily of cash and cash equivalents and restricted cash. The Partnership places its cash and cash equivalents and restricted cash with creditworthy institutions located in Canada, which the management believes to have minimal risk. At times, such balances may be in excess of the Canada Deposit Insurance Corporation (CDIC) insurance coverage limit. CDIC insurance currently covers up to $100 per depositor at each insured bank.
The IESO is the only customer of the Partnership, which is obligated to pay for 100% of the electrical output under a long-term, fixed priced PPA. There are no accounts receivable that are past due.
The Partnership's derivative agreements expose the Partnership to losses under certain circumstances, such as the counterparty defaulting on its obligations under the swap agreements or if the swap agreements provide an imperfect hedge. Counterparties to the Partnership's derivative contracts are major financial institutions that have been accorded investment grade ratings.
Property, plant and equipment
Property, plant and equipment are stated at historical cost, less accumulated depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Subsequent costs are included in the asset's carrying value or recognized as separate assets, as appropriate, only when it is probable that the future economic benefits associated with the item will flow to the Partnership and the cost of the item can be reliably measured.

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The asset retirement obligation included in property, plant and equipment is stated at the present value of future cash flows of asset retirement obligation at the time of COD.

Depreciation on property, plant and equipment is calculated using the straight-line method to allocate their cost to their residual values over their estimated useful lives. The power plant is depreciated over 25 years and the remaining assets are depreciated over 5 years. The assets' residual values and useful lives are reviewed and adjusted, if appropriate, at the end of each reporting period. Repair and maintenance costs are expensed as incurred.

Intangible assets

Amortization is calculated using the straight-line method and recorded against revenue over the remaining term of the PPA.

Impairment of long-lived assets

The Partnership periodically evaluates whether events have occurred that would require revision of the remaining useful life of equipment and improvements and purchased intangible assets, or render them not recoverable. If such circumstances arise, the Partnership uses an estimate of the undiscounted value of expected future operating cash flows to determine whether the long-lived assets are impaired. If the aggregate undiscounted cash flows are less than the carrying amount of the assets, the resulting impairment charge to be recorded is calculated based on the excess of the carrying value of the assets over the fair value of such assets, with the fair value determined based on an estimate of discounted future cash flows. Through December 31, 2015, no impairment charges were recorded.

Deferred financing costs

Financing costs incurred in connection with obtaining construction and term financing, which include direct financing, legal and other upfront costs of borrowing, are capitalized and recorded as a reduction to long-term debt and amortized over the lives of the respective loans using the effective-interest method. Amortization of deferred financing costs is capitalized during construction or expensed following COD.

Interest capitalization

The Partnership capitalizes interest and related financing fees from non-recourse debt used to finance projects in construction. Capitalization is discontinued when a project reaches commercial operation.

Derivatives

The Partnership recognizes its derivative instruments as either assets or liabilities in the balance sheets at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it qualifies and has been designated as part of a hedging relationship and the type of hedging relationship.

For derivative instruments that are designated and qualify as a cash flow hedge (i.e., hedging the exposure to variability in expected future cash flows that are attributable to a particular risk), the effective portion of the gain or loss on the derivative instrument is reported as a component of other comprehensive income (OCI) or loss (OCL). Changes in the fair value of these derivatives are subsequently reclassified into earnings in the period that the hedged transaction affects earnings. The ineffective portion of changes in fair value is recorded as a component of net income (loss) in the statements of operations and comprehensive income (loss).

For undesignated derivative instruments, their change in fair value is reported as a component of net income in the statements of operations and comprehensive income (loss).

The Partnership enters into derivative transactions for the purpose of managing exposure to fluctuations in interest rates, such as interest rate swaps. Interest rate swaps are instruments used to fix the interest rate on variable interest rate debt.

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Accounts payable and other accrued liabilities
Trade payables are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers. Payables with payment terms extended beyond one year from the balance sheet dates are presented as non-current liabilities.
Contingent liabilities
Contingent liabilities are recognized when: the Partnership has a present legal obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and the amount has been reasonably estimated.
Asset retirement obligation
The Partnership records an asset retirement obligation for the estimated costs of decommissioning turbines, removing above-ground installations and restoring sites, at the time when a contractual decommissioning obligation materializes. The Partnership records accretion expense, which represents the increase in the asset retirement obligation, over the remaining life of the associated wind project. Accretion expense is recorded as cost of revenue in the statements of operations and comprehensive income (loss) using accretion rates based on a credit adjusted risk free interest rate of 6.51%.
Revenue recognition
The Partnership sells the electricity it generates under the terms of a PPA with the IESO. Revenue is recognized based upon the amount of electricity delivered or curtailed at rates specified under the contracts, assuming all other revenue recognition criteria are met. The Partnership evaluates its PPA to determine whether it is in substance a lease or derivative and, if applicable, recognizes revenue pursuant to ASC 840 Leases and ASC 815 Derivatives and Hedging, respectively. As of December 31, 2015, the PPA was not accounted for as a lease or derivative and revenue was recognized on an accrual basis.
The Partnership recognizes revenue for warranty settlements and liquidated damages from a turbine manufacturer in other revenue upon resolution of outstanding contingencies. Any cash receipts for amounts subject to future adjustment or repayment are deferred in other liabilities until the final settlement amount is considered fixed and determinable.
Cost of revenue
The Partnership's cost of revenue is comprised of direct costs of operating and maintaining its project facilities, including labor, turbine service arrangements, metering service and shadow settlement, environmental fee, land lease royalties, property tax, insurance, depreciation, amortization and accretion.
Comprehensive income
Comprehensive income consists of net income and other comprehensive income. Other comprehensive income is included in accumulated other comprehensive income in the accompanying statements of changes in partners' equity.
Reclassification
Certain prior period balances have been reclassified to conform to current period presentation of the Partnership's financial statements and accompanying notes. Such reclassifications did not have an impact on net income (loss) or cash flows.
Recent accounting pronouncements
In April 2015, the Financial Accounting Standard Board (FASB) issued ASU 2015-03, "Interest - Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs" to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the amendments in this ASU. ASU 2015-03 is

effective for public companies for fiscal years beginning after December 15, 2015, and

Grand Renewable Wind LP
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interim periods within those fiscal years and should be applied retrospectively. Early adoption is permitted for financial statements that have not been previously issued. Upon transition, an entity is required to comply with the applicable disclosures for a change in accounting principle. The Partnership adopted ASU 2015-03 in April 2015 and applied the change in accounting principle to the financial statements as of December 31, 2015. As a result, the Partnership reclassified $8,304 and $9,897 in total deferred financing costs to long-term debt, of which $1,597 and $1,627 have been reclassified to current portion of long-term debt, as of December 31, 2015 and December 31, 2014, respectively, on the Partnership's balance sheets. The adoption of ASU 2015-3 had no impact on the Partnership's results of operations and cash flows.

New standards, amendments and interpretations were issued but not effective for the financial period ended December 31, 2015 and were not early adopted. The Partnership intends to adopt these standards, if applicable, when they become effective.

In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers: Deferral of the Effective Date" to amend ASU 2015-09 "Revenue from Contracts with Customers" to defer the effective date of ASU 2014-09 for all entities by one year. The guidance in ASU 2014-09 provides companies with a single model for use in accounting for revenue arising from contracts with customers and supersedes current revenue recognition guidance, including industry-specific revenue guidance. The core principle of the model is to recognize revenue when control of the goods or services transfers to the customer, as opposed to recognizing revenue when the risks and rewards transfer to the customer under the existing revenue guidance. As a result of this amendment, ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017 and interim periods within those fiscal years. Early adoption is permitted only as of annual reporting periods beginning after December 15, 2015 and interim periods within those fiscal years. The guidance permits companies to either apply the requirements retrospectively to all prior periods presented, or apply the requirements in the year of adoption, through a cumulative adjustment. In June 2015, the FASB voted to defer the effective date by one year, with early adoption permitted as of the original effective date. The Partnership is currently assessing the future impact of this update on its financial statements and related disclosures and expects to adopt this update beginning January 1, 2018.

In June 2015, the FASB issued ASU 2015-10, "Technical Corrections and Improvements" which covers a wide range of topics in the Accounting Standards Codification (the "Codification"). The amendments in this update represent changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice or create a significant administrative cost on most entities. The amendments in ASU 2015-10 were effective immediately upon issuance and the adoption did not have material impact on the Partnership's financial statements and related disclosures.

3 Restricted cash

The following table presents the components of restricted cash:

	December 31,	
	2015	2014
Completion reserve account	$8,986	$—
Siemens incentive reserve account	2,234	—
Security deposit for letter of guarantee	—	4,812
10% holdback account for contractors	1,221	1,416
Distribution account	6	—
Subtotal	12,447	6,228
Less: current portion	(3,461)	(6,228)
Restricted cash, non-current	$8,986	$—

The amount in the completion reserve account is reserved to pay outstanding project costs specified during term conversion (note 6). Upon full payment of outstanding project costs, the remaining balance will be released from restricted cash.

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The amount in the Siemens incentive account is reserved to pay operational incentive payments to Siemens if it is confirmed in early 2016 that the Siemens Three-Year Employment Objective was achieved by December 31, 2015 (note 10).

The letter of guarantee was canceled and the restricted term deposit was released in 2015 as the Project achieved COD.

4 Property, plant and equipment

The following is a summary of property, plant and equipment, at cost less accumulated depreciation, at December 31:

	December 31, 2015	2014
Power plant	$430,198	$412,201
Furniture, fixture and equipment	240	155
Asset retirement obligation - asset	2,463	3,062
Subtotal	432,901	415,418
Less: Accumulated depreciation	(18,687)	(1,350)
	$414,214	$414,068

Depreciation expense of $17,337, $1,326 and $24 was charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively, and $0 and $12 was capitalized to property, plant and equipment on the balance sheets as of December 31, 2015 and 2014, respectively.

5 Intangible assets

	December 31, 2015	2014
Beginning net book value	$1,665	$—
Additions (note 2)	—	1,672
Amortization expense	(84)	(7)
Closing net book value	$1,581	$1,665

	December 31, 2015	2014
Cost	$1,672	$1,672
Accumulated amortization	(91)	(7)
Net book value	$1,581	$1,665

Cash consideration of $1,672 was paid to the IESO to extend the end of PPA term by 74 days from September 24, 2034 to December 8, 2034, which is recorded in intangible assets on the balance sheets as of December 31, 2015. Amortization expense of $84, $7, and $0 was charged as a reduction to revenue in the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively.

6 Long-term debt

On September 13, 2013, the Partnership signed a credit facility agreement with a syndicate of lenders consisting of 11 different financial institutions for a term of construction period plus 7 years at a rate of Canadian Dealer Offered Rate (CDOR) plus 2.25% per annum. The credit facilities under the agreement include $395,383 construction facility, term facility, letter of credit facility and

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an interest rate hedge facility. The funds from these facilities were utilized to finance the construction of the Project and to run the Project's operations

The Partnership reached full commercial operations in December 2014, and the construction facility converted to term loan on July 29, 2015. The loan matures on July 29, 2022. In connection with the financing agreement, the Partnership entered into interest rate swaps on 90% of the loan commitment. Interest payments on the construction facility were deferred prior to term conversion and added to the loan principal at the time of conversion.

Collateral under the financing agreement consists of substantially all of the Partnership's assets. The loan agreement contains a broad range of covenants that, subject to certain exceptions, restrict the Partnership's ability to incur debt, grant liens, sell or lease assets, transfer equity interest, dissolve, pay distributions and change its business. The Partnership is in compliance with all loan covenants. All of the limited and general partners and shareholders of general partners pledged shares of partnership units or common stock owned as collateral for the loan.

Terms and conditions of outstanding borrowings were as follows:

	As of December 31, 2015				
	Principal	Deferred financing costs	Net of financing costs	Interest rate	Maturity date
Term loan	$383,210	$(8,304)	$374,906	3.13%	July 2022
Less: current	(13,897)	1,597	(12,300)		
Net of current	$369,313	$(6,707)	$362,606		

	As of December 31, 2014				
	Principal	Deferred financing costs	Net of financing costs	Interest rate	Maturity date
Construction facility loan	$349,583	$(9,897)	$339,686	3.54%	March 2022
Less: current	(9,172)	1,627	(7,545)		
Net of current	$340,411	$(8,270)	$332,141		

Future maturities of long-term debt are as follows as of December 31, 2015:

2016	$13,897
2017	14,538
2018	17,371
2019	18,418
2020	19,525
Thereafter	299,461
	$383,210

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The following table presents a reconciliation of interest expense presented in the Partnerships' statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013:

	2015	2014	2013
Interest incurred	$20,023	$10,320	$518
Commitment fees incurred	342	1,516	978
Amortization of deferred financing costs	1,593	1,016	50
Less: Capitalized interest, commitment and amortization	—	(11,155)	(1,399)
Interest expense	$21,958	$1,697	$147

Revolving credit facility

On July 29, 2015, letters of credit of $24,000, $8,000 and $$5,000 were issued upon term conversion for a debt service reserve, operations and maintenance reserve, and decommissioning reserve, respectively, with a seven-year term. Funds, when and if drawn on the facility, accrue interest at 1.25% plus Prime Rate, and at the partners' option, the rate can be converted to a rate of CDOR plus 2.25% per annum. In addition, the Partnership shall pay letter of credit fees on the basis of the undrawn amount of the facility at 2.25% per annum. As of December 31, 2015, the letters of credit facility did not have an outstanding balance, and no amounts were drawn in 2015. Letter of credit fees of $354 were charged to other expense in the statements of operations and comprehensive income (loss) for the year ended December 31, 2015.

7 Asset retirement obligation

The Partnership's asset retirement obligation represents the estimated cost of decommissioning the turbines, removing above-ground installations and restoring the sites at the end of its estimated useful life. Effective January 1, 2015, the Partnership changed its estimate of the useful life of the power plant from 20 years to 25 years. As a result, during the year ended December 31, 2015, the Partnership recorded a one-time adjustment of $598 to reduce the carrying amount of the asset retirement obligations to reflect the change in estimate associated with the timing of the original undiscounted cash flows.

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

	December 31,	
	2015	2014
Asset retirement obligation - Beginning of year	$3,074	$496
Additions	—	2,566
Adjustment related to change in useful life	(598)	
Accretion expense	161	12
Asset retirement obligation - End of year	$2,637	$3,074

8 Derivatives

The Partnership uses interest rate derivatives to manage its exposure to fluctuations in interest rates. Interest rate risk exists primarily on variable-rate debt for which the cash flows vary based upon movement in market prices. The Partnership's objectives for holding these derivative instruments include reducing, eliminating and efficiently managing the economic impact of interest rate exposures as effectively as possible. The Partnership does not hedge all of its interest rate risks, thereby exposing the unhedged portions to changes in market prices.

As of December 31, 2015, the Partnership had other energy-related contracts that did not meet the definition of a derivative instrument and were therefore exempt from fair value accounting treatment.

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The following tables present the fair values of the Partnership's derivative instruments on a gross basis as reflected on the Partnership’s balance sheets:

	December 31, 2015		December 31, 2014	
	Derivative liabilities		Derivative liabilities	
	Current	Long-term	Current	Long-term
Fair value of designated derivatives:				
Interest rate swaps	$8,643	$25,215	$7,040	$20,741
Fair value of undesignated derivatives:				
Interest rate swaps	$—	$20,672	$—	$17,318
Total fair value	$8,643	$45,887	$7,040	$38,059

The following table summarizes the notional amounts of the Partnership's outstanding derivative instruments:

		December 31	
	Unit of measure	2015	2014
Designated derivative instruments			
Interest rate swaps	CAD	$347,590	$355,845

The following table presents losses on derivative contracts designated and qualifying as cash flow hedges recognized in accumulated other comprehensive loss, as well as, losses on other derivative contracts and amounts reclassified to earning for the following periods:

		December 31	
	Description	2015	2014
Losses recognized in accumulated OCL	Effective portion	$(6,077)	$(18,934)
Losses recognized in earnings on other derivative contracts	Effective portion	$(3,354)	$(16,072)
Losses reclassified from accumulated OCL into interest expense	Derivative settlements	$(8,320)	$—

No ineffectiveness was recorded on these swaps for the years ended December 31, 2015 and 2014. The Partnership estimates that $8,480 in accumulated other comprehensive loss will be reclassified into earnings over the next twelve months.

9 Fair value measurement

The Partnership’s fair value measurements incorporate various factors, including the credit standing and performance risk of the counterparties, the applicable exit market, and specific risks inherent in the instrument. Non-performance and credit risk adjustments on risk management instruments are based on current market inputs when available, such as credit default hedge spreads. When such information is not available, internal models are used.

Assets and liabilities recorded at fair value in the financial statements are categorized based upon the level of judgment associated with the inputs used to measure their fair value. Hierarchical levels directly related to the amount of subjectivity associated with the inputs to valuation of these assets or liabilities are as follows:

Level 1 - Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

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Level 2 - Inputs (other than quoted prices included in Level 1) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.
Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities and which reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.
Short-term financial instruments consist principally of cash and cash equivalents, restricted cash, and accounts payable and other accrued liabilities. Based on the nature and short maturity of these instruments their fair value is approximated using carrying cost and they are presented in the financial statements at carrying cost.
Long term debt is presented on the balance sheets at amortized cost. The fair value of the Partnership's long-term debt is approximately $404,231 and $418,757 as of December 31, 2015 and 2014, respectively. It is estimated based on current rates that would be available for debt of similar terms which is not significantly different from its stated value.
Derivatives are presented in the financial statements at fair value. The interest rate swaps were valued by discounting the net cash flows using the forward CDOR curve with the valuations adjusted by the Project's credit default swap rate.
The Partnership's financial assets (liabilities) which require fair value measurement on a recurring basis are classified within the fair value hierarchy as follows:

	Level 1	Level 2	Level 3
December 31, 2015			
Interest rate swaps	$—	$(54,530)	$—
December 31, 2014			
Interest rate swaps	$—	$(45,099)	$—

10 Commitments and contingencies
1) Commitments
Power Purchase Agreement
The Partnership entered into a PPA with the Ontario Power Authority on August 2, 2011, which subsequently merged with the IESO. The term of the PPA provides for the annual delivery of electricity at fixed prices with price escalation for 20% of the fixed price over the duration of the PPA, which is 20 years from COD.
Land Lease Agreements
The Partnership has entered into various long-term land lease agreements. The annual fees range from minimum rent payments varying by lease to maximum rent payments of a certain percentage of energy delivered revenues, varying by lease.
Lease payments, including amortization of the lease option, of $1,864, $0 and $0 were charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively, and $0 and $430 were capitalized to property, plant and equipment in the balance sheets as of December 31, 2015 and 2014, respectively.

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Future minimum payments related to leases as of December 31, 2015 are as follows:

2016	$1,859
2017	1,896
2018	1,934
2019	1,972
2020	2,012
Thereafter	35,466
Total	$45,139

Service and Maintenance Agreement

The Partnership has entered into service and maintenance agreements with Siemens to provide and carry out turbine maintenance and service activities for the Project until January 2018. Based on the terms of the agreements, Siemens shall be entitled to receive a daily base fee per turbine that may be subject to periodic price adjustments for inflation, over the terms of the agreements. As of December 31, 2015, outstanding commitments with Siemens were $7,710, including an estimated annual price adjustment for inflation of 2%, where applicable, payable over the full term of the agreement.

Operational Incentive Agreement

On March 8, 2013, an Operational Incentive Agreement was entered into between Samsung, an affiliate of PRHC and Siemens Canada Limited to define operational objectives and the terms and conditions upon which the Partnership may pay operational incentive payments to Siemens for achieving one or more of such operational objectives under the turbine supply agreements of certain projects under development by Samsung and affiliates of PRHC, including the Project. $1,976 was recorded as accrued liabilities which will be due to Siemens if it is confirmed in early 2016 that the Siemens Three-Year Employment Objective was achieved by December 31, 2015 (note 3).

The operational incentive payment shall not exceed any of the applicable maximums of (a) $0.02 per kW of the agreed de-rated capacity (270MWh) of wind turbines purchased under the TSA for the Project, and (b) an aggregate of $15,000 under all TSAs for all projects subject to the Operational Incentive Agreement, including the Project, and other affiliated wind projects.

2) Contingencies

Community Vibrancy Fund

On September 26, 2011, the Partnership entered into a Community Vibrancy Fund (CVF) Agreement with the Corporation of Haldimand County, in which the Partnership will make annual payments into a fund managed by the municipality in amounts of $3.5 per MW of the Project installed capacity plus $5 per kilometer (km) of high voltage overhead transmission line that is installed in municipal right-of-way. The payments are calculated annually and are owed for the 20-year term of the PPA. In exchange for CVF payments, the municipality undertakes certain obligations to support the Project, including entering into a road use agreement in which the Project may utilize municipal right-of-ways for collection and transmission lines.

Turbine Availability Warranty

The Partnership has a turbine availability warranty from its turbine manufacturer. Pursuant to the warranty, if a turbine operates at less than minimum availability during the warranty period, the turbine manufacturer is obligated to pay, as liquidated damages, an amount for each percent that the turbine operates below the minimum availability threshold. In addition, if a turbine operates at more than a specified availability during the warranty period, the Partnership has an obligation to pay a bonus to the turbine manufacturer. As of December 31, 2015, the Partnership recorded a liability of $342 associated with bonuses payable to the turbine manufacturer.

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11 Related party transactions

The Partnership is controlled by the GP, which is jointly controlled by Samsung and Pattern in accordance with the terms of the Shareholder Agreement. Certain terms of the Samsung and Pattern Joint Venture Wind Development Agreement, entered into between Samsung and an affiliate of PRHC on July 27, 2010, directed the responsibilities of Samsung and PRHC during the development of the Project.

The following transactions were carried out with related parties:

a) Management, Operation, and Maintenance Agreement (MOMA)

Balance of Plant MOMA

On September 13, 2013, the Partnership entered into a MOMA with Pattern Operators Canada ULC, which is owned by PCOH to operate and manage the maintenance of the wind plant and to perform certain other services pertaining to the wind plant in accordance with terms and conditions set in the MOMA.

The amounts of $1,187 and $787 were invoiced to the Partnership for the years ended December 31, 2015 and 2014, respectively, of which $0 and $715 was capitalized to property, plant and equipment as of December 31, 2015 and 2014, respectively, and $1,187, $73 and $0 were charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively.

Transmission Line MOMA (TL MOMA)

On September 13, 2013, the Partnership and Grand Renewable Solar LP entered into TL MOMA with Pattern Operators Canada ULC, which is 100% owned by an affiliate of Pattern, to operate and manage the maintenance of the transmission line and common assets of the substation and to perform certain other services pertaining to the wind plant in accordance with terms and conditions set in TL MOMA.

The amounts of $0 and $5 were capitalized to property, plant and equipment as of December 31, 2015 and 2014, respectively, and $57, $2 and $0 were charged to the statements of operations and comprehensive income for the years ended December 31, 2015, 2014 and 2013, respectively.

b) Engineering Procurement and Construction Contract (EPC contract)

Balance of Plant EPC

On September 13, 2013, the Partnership entered into the Balance of Plant EPC contract with SRE GRW EPC LP, which is 100% owned by Samsung to build the balance of plant, and $1,576 and $95,780 were capitalized to property, plant and equipment on the balance sheets as of December 31, 2015 and 2014, respectively.

Transmission Line EPC

On September 13, 2013, the Partnership entered into TL EPC contract with Grand Renewable Solar LP, and SRE GRW EPC LP, which is 100% owned by Samsung to build the transmission line, and $188 and $14,732 were capitalized to property, plant and equipment on the balance sheets as of December 31, 2015 and 2014, respectively.

c) Project Administration Agreement (PAA)

On September 31, 2013, the Partnership entered into PAA with SRE Wind PA LP (PA), which is 100% owned by Samsung to receive project administrative services.

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$406, $288 and $433 were charged to the statements of operations and comprehensive income (loss) for the years ended December 31, 2015, 2014 and 2013, respectively.

d) Transmission Facilities Co-ownership Agreement (TFCA)

On March 8, 2013, the Partnership entered into the TFCA with a planned 100 MW solar project developed by an affiliate of Samsung which provides for the co-ownership of the transmission line and substation of the Project. Under the co-ownership agreement, the Project and the solar project each contributed 50% of the construction and operating costs of the transmission line and substation and each received a 50% undivided interest in such shared facilities.

e) The Partnership recorded the following balances with related parties:

	2015	2014
Related party payable to Pattern Operators Canada ULC	$187	$109
Related party payable to SRE Wind PA LP	$38	$35
Related party payable and accrued liabilities to SRE GRW EPC LP	$1,220	$4,130
Accrued liabilities to prime-sub contractor (note 1)	$4,000	$—

12 Subsequent events

There were no material subsequent events.