TRANSGLOBE ENERGY CORP
Form 6-K
August 24, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER TO RULE 13A or 15D-16
UNDER THE SECURITIES EXCHANGE ACT OF 1934

For the Month of: August 2004 (4) **File No.: 0-11378**

TRANSGLOBE ENERGY CORPORATION

(Translation of Registrant s Name into English)

#2900, 330 5th Avenue S.W., Calgary, AB T2P 0L4

(Address of Principal Executive Office)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20F or Form 40F
Form 20F ¨ Form 40F **x**

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.
Yes ¨ No **x**

If Yes is marked, indicate below the file number assigned to the registrant in connection with rule 12g-3-2(b): 82 - _______.

SUBMITTED HEREWITH

Exhibit	**Description**
99.1	**Material Change Form 27** - Report dated August 23, 2004 - Press Release dated August 23, 2004 -TransGlobe Energy Corporation Announces Operations Update.

SIGNATURES

Pursuant to the requirements 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.

TransGlobe Energy Corporation
(Registrant)

Date: August 23, 2004

By: */s/ Lloyd Herrick*
Lloyd W. Herrick
Vice President & C.O.O.

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Date of Earliest Event Reported:

October 29, 2004

OFFICEMAX INCORPORATED

(Exact name of registrant as specified in its charter)

Delaware	**1-5057**	**82-0100960**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

150 Pierce Road	
Itasca, Illinois	**60143**
(Address of principal executive offices)	(Zip Code)

(630) 773-5000

(Registrant s telephone number, including area code)

Not Applicable

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

This current report on Form 8-K/A is being filed to amend Item 9.01 Financial Statements and Exhibits of the current report on Form 8-K filed by OfficeMax Incorporated with the Securities and Exchange Commission on November 4, 2004. The unaudited pro forma condensed statements of income (loss) for the year ended December 31, 2003, and the six months ended June 30, 2004, understated sales and costs and expenses related to intercompany eliminations and classifications. The effect of the correction increases sales and costs and expenses, but has no effect on pro forma net income (loss).

Item 9.01 Financial Statements and Exhibits.

(b) Pro Forma Financial Information.

Unaudited Pro Forma Condensed Balance Sheet as of June 30, 2004

Unaudited Pro Forma Condensed Statement of Income (Loss) for the year ended December 31, 2003

Unaudited Pro Forma Condensed Statement of Income (Loss) for the six months ended June 30, 2004

Notes to Unaudited Pro Forma Condensed Financial Statements

(c) Exhibits.

Exhibit 99.2	Unaudited Pro Forma Condensed Balance Sheet as of June 30, 2004
	Unaudited Pro Forma Condensed Statement of Income (Loss) for the year ended December 31, 2003
	Unaudited Pro Forma Condensed Statement of Income (Loss) for the six months ended June 30, 2004
	Notes to Unaudited Pro Forma Condensed Financial Statements

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

OFFICEMAX INCORPORATED

By /s/ Matthew R. Broad
Matthew R. Broad

Executive Vice President, General Counsel

Date: November 12, 2004

EXHIBIT INDEX

Number	Description
99.2	Unaudited Pro Forma Condensed Balance Sheet as of June 30, 2004
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	Notes to Unaudited Pro Forma Condensed Financial Statements

Times New Roman,Times,serif;font-size: 10pt;">

Change in fair value of derivative instruments

2.9

—

3.9

—

6.8

Equity in earnings of unconsolidated affiliates

8.2

0.4

—

—

8.6

Interest expense, net

(2.0)

—

—

—

(2.0)

Other expense, net

—

—

—

2.2

2.2

9.1

0.4

3.9

2.2

15.6

Project income (loss)

$

16.7

$

(4.3)

$

2.8

$

2.0

$

17.2

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(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended June 30, 2015. The Wind Projects were sold in June 2015.

East U.S.

Project income for the three months ended June 30, 2016 decreased $7.1 million from the comparable 2015 period primarily due to:

- decreased project income of $3.1 million at Curtis Palmer primarily due to lower water flow than the comparable period in 2015;

- decreased project income of $2.9 million at Piedmont primarily due to a $2.1 million decrease in change in fair value of derivatives, a $0.4 million increase in interest expense and a $0.3 million decrease in energy sales; and

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· decreased project income of $2.4 million at Morris primarily due to a $1.3 million decrease in capacity revenue from lower gas prices, a $0.7 million decrease in change in fair value of derivatives and a $0.3 million increase in depreciation.

These decreases were partially offset by:

· Increased project income of $2.3 million at Orlando primarily due to a $2.4 million increase in change in fair value of derivatives.

West U.S.

Project income for the three months ended June 30, 2016 increased $8.9 million from the comparable 2015 period primarily due to:

· increased project income of $8.3 million at Manchief primarily due to lower maintenance costs than the comparable period in 2015. Manchief underwent a scheduled maintenance overhaul outage during the second quarter of 2015.

Canada

Project income for the three months ended June 30, 2016 increased $10.1 million from the comparable 2015 period primarily due to:

· increased project income of $2.8 million at Nipigon primarily due to a positive $3.0 million change in the fair value of gas purchase agreements that are accounted for as derivatives;

· increased project income of $2.0 million at Williams Lake due to a $2.6 million decrease in depreciation expenses resulting from a long-lived asset impairment recorded in the fourth quarter of December 31, 2015, offset by lower energy revenue;

· increased project income of $1.9 million at Mamquam primarily due to a $1.7 million increase in energy sales from higher water flow than the comparable period in 2015;

· increased project income of $1.6 million at North Bay primarily due to a positive $2.4 million change in the fair value of gas purchase agreements that are accounted for as derivatives, offset by a $1.1 million increase in operations and maintenance cost; and

· increased project income of $1.4 million at Kapuskasing primarily due to a positive $2.4 million change in the fair value of gas purchase agreements that are accounted for as derivatives, offset by a $1.1 million increase in operations and maintenance cost.

Un allocated Corporate

Total project loss for the three months ended June 30, 2016 increased by $3.9 million from the comparable 2015 period primarily due to a $2.3 million gain on sale of the Frontier solar development project in 2015 and a $1.9 million decrease in the fair value of interest rate swap agreements at APLP.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to any specific project and is allocated to the Un allocated Corporate segment. These costs include the activities that support the executive and administrative offices, treasury function, costs of being a public registrant, costs to develop or acquire future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate taxes. Significant non cash items that impact Administrative and other expenses (income), and that are subject to potentially significant fluctuations include the non cash impact of foreign exchange fluctuations from period to period on

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the U.S. dollar equivalent of our Canadian dollar denominated obligations and the related deferred income tax expense (benefit) associated with these non cash items.

Administration

Administration expense decreased $0.8 million or 12.1% from the comparable 2015 period primarily due to a $0.3 million decrease in compensation costs and a $0.3 million decrease in rent expense.

Interest, net

Interest expense increased $26.6 million or 108.1% from the comparable 2015 period primarily due to $31.4 million of deferred financing costs written off related to the Senior Secured Credit Facilities and repurchase and cancellation of convertible debentures. This was partially offset by lower interest expense related to the 9.0% Notes that were redeemed in July 2015.

Foreign exchange loss (gain)

Foreign exchange loss decreased $2.2 million, or 45.8%, from the comparable 2015 period primarily due to a $2.7 million decrease in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The closing U.S. dollar to Canadian dollar exchange rates were 1.29 and 1.25 at June 30, 2016 and 2015, respectively, a decrease of 0.5% as compared to a decrease of 1.4% in 2015. The average U.S. dollar to Canadian dollar exchange rates were 1.29 and 1.25 for the three months ended June 30, 2016 and 2015, respectively.

Other expense, net

Other expense, net increased $2.0 million primarily due to a $1.7 million gain on repurchase of convertible debentures in the comparable 2015 period.

Income tax expense

Income tax benefit for the three months ended June 30, 2016 was $18.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $9.0 million. The primary items impacting the tax rate for the three months ended June 30, 2016 were $4.6 million related to capital gain on intercompany notes, $2.6 million related to foreign exchange, $1.8 million relating to a change in the valuation allowance and $0.4 million of other permanent differences. These items were partially offset by $18.8 million related to capital loss recognized on tax restructuring.

Income tax expense for the three months ended June 30, 2015 was $2.9 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $4.4 million. The primary items impacting the tax rate for the three months ended June 30, 2015 were $9.0 million relating to a change in the valuation allowance, $3.4 million of dividend withholding and other state taxes, and $2.5 million of other permanent differences. These items were partially offset by $3.6 million relating to tax credits, $2.4 million relating to foreign exchange and $1.6 million relating to operating in higher tax rate jurisdictions.

Six months ended June 30, 2016 compared to the six months ended June 30, 2015

The following table provides our consolidated results of operations:

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	Six months ended June 30, 2016	2015	$ change	% change
Project revenue:				
Energy sales	$ 97.6	$ 101.5	$ (3.9)	(3.8) %
Energy capacity revenue	69.2	71.5	(2.3)	(3.2) %
Other	37.8	41.4	(3.6)	(8.7) %
	204.6	214.4	(9.8)	(4.6) %
Project expenses:				
Fuel	74.0	84.2	(10.2)	(12.1) %
Operations and maintenance	51.2	56.8	(5.6)	(9.9) %
Development	—	1.1	(1.1)	(100.0) %
Depreciation and amortization	50.3	56.1	(5.8)	(10.3) %
	175.5	198.2	(22.7)	(11.5) %
Project other income:				
Change in fair value of derivative instruments	11.0	5.2	5.8	111.5 %
Equity in earnings of unconsolidated affiliates	18.3	19.3	(1.0)	(5.2) %
Interest expense, net	(4.5)	(4.1)	(0.4)	9.8 %
Other income, net	—	2.2	(2.2)	(100.0) %
	24.8	22.6	2.2	9.7 %
Project income	53.9	38.8	15.1	38.9 %
Administrative and other expenses (income):				
Administration	11.9	16.0	(4.1)	(25.6) %
Interest, net	67.8	50.3	17.5	34.8 %
Foreign exchange loss (gain)	22.5	(27.4)	49.9	NM
Other income, net	(2.2)	(3.1)	0.9	(29.0) %
	100.0	35.8	64.2	179.3 %
(Loss) income from continuing operations before income taxes	(46.1)	3.0	(49.1)	NM
Income tax benefit	(16.8)	(1.7)	(15.1)	NM
Income (loss) from continuing operations	(29.3)	4.7	(34.0)	NM
Income from discontinued operations, net of tax	—	21.1	(21.1)	NM
Net (loss) income	(29.3)	25.8	(55.1)	NM
Net loss attributable to noncontrolling interests	—	(11.0)	11.0	(100.0) %
Net income attributable to Preferred share dividends of a subsidiary company	4.2	4.6	(0.4)	(8.7) %
Net (loss) income attributable to Atlantic Power Corporation	$ (33.5)	$ 32.2	$ (65.7)	NM

	Six months ended June 30, 2016				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 39.9	$ 14.0	$ 43.7	$ —	$ 97.6
Energy capacity revenue	24.8	19.9	24.5	—	69.2
Other	8.4	10.6	18.3	0.5	37.8

	73.1	44.5	86.5	0.5	204.6
Project expenses:					
Fuel	25.7	15.9	32.4	—	74.0
Operations and maintenance	19.0	13.0	18.5	0.7	51.2
Depreciation and amortization	17.0	14.6	18.4	0.3	50.3
	61.7	43.5	69.3	1.0	175.5
Project other income (expense):					
Change in fair value of derivative instruments	1.7	—	12.1	(2.8)	11.0
Equity in earnings of unconsolidated affiliates	17.0	1.3	—	—	18.3
Interest expense, net	(4.5)	—	—	—	(4.5)
Other expense, net	—	—	—	—	—
	14.2	1.3	12.1	(2.8)	24.8
Project income (loss)	$ 25.6	$ 2.3	$ 29.3	$ (3.3)	$ 53.9

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	Six months ended June 30, 2015				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total (1)
Project revenue:					
Energy sales	$ 40.0	$ 18.8	$ 42.7	$ —	$ 101.5
Energy capacity revenue	26.3	19.8	25.4	—	71.5
Other	10.2	10.7	20.1	0.4	41.4
	76.5	49.3	88.2	0.4	214.4
Project expenses:					
Fuel	29.9	19.5	34.8	—	84.2
Operations and maintenance	16.6	20.5	18.2	1.5	56.8
Development	—	—	—	1.1	1.1
Depreciation and amortization	16.4	14.5	24.8	0.4	56.1
	62.9	54.5	77.8	3.0	198.2
Project other income (expense):					
Change in fair value of derivative instruments	0.4	—	5.6	(0.8)	5.2
Equity in earnings of unconsolidated affiliates	18.1	1.2	—	—	19.3
Interest expense, net	(4.1)	—	—	—	(4.1)
Other (expense) income, net	—	—	—	2.2	2.2
	14.4	1.2	5.6	1.4	22.6
Project income (loss)	$ 28.0	$ (4.0)	$ 16.0	$ (1.2)	$ 38.8

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended June 30, 2015. The Wind Projects were sold in June 2015.

East U.S.

Project income for the six months ended June 30, 2016 decreased $2.4 million from the comparable 2015 period primarily due to:

- decreased project income of $3.5 million at Piedmont primarily due to lower energy rates and higher fuel usage due to wet weather; and

- decreased project income of $2.5 million at Morris primarily due to lower gas prices than the comparable period in 2015.

These decreases were partially offset by:

· Increased project income of $4.6 million at Orlando primarily due to a $4.8 million increase in change in fair value of derivatives.

West U.S.

Project income for the six months ended June 30, 2016 increased $6.3 million from the comparable 2015 period primarily due to:

· increased project income of $7.9 million at Manchief primarily due to a scheduled maintenance overhaul outage resulting in higher maintenance costs in the comparable period in 2015.

Canada

Project income for the six months ended June 30, 2016 increased $13.3 million from the comparable 2015 period primarily due to:

· increased project income of $4.8 million at Williams Lake due to a $5.3 million decrease in depreciation expenses resulting from a long-lived asset impairment recorded in the fourth quarter of December 31, 2015;

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- increased project income of $3.1 million at Mamquam primarily due to a $3.0 million increase in energy sales from higher water flows than the comparable period in 2015;
- increased project income of $2.1 million at Nipigon primarily due to a positive $2.2 million change in the fair value of gas purchase agreements that are accounted for as derivatives;
- increased project income of $1.7 million at North Bay primarily due to a positive $2.2 million change in the fair value of gas purchase agreements that are accounted for as derivatives; and
- increased project income of $1.2 million at Kapuskasing primarily due to a positive $2.2 million change in the fair value of gas purchase agreements that are accounted for as derivatives, offset by a $1.0 million decrease in revenue due to a maintenance outage.

Un allocated Corporate

Total project loss for the six months ended June 30, 2016 decreased by $2.1 million from the comparable 2015 period primarily due to a $2.0 million decrease in the fair value of interest rate swap agreements at APLP.

Administrative and other expenses (income)

Administration

Administration expense decreased $4.1 million or 25.6% from the comparable 2015 period primarily due to a $2.0 million decrease in employee compensation expense, a $1.0 million decrease in professional services and a $1.1 million decrease in rent expense.

Interest, net

Interest expense increased $17.5 million or 34.8% from the comparable 2015 period primarily due to $31.4 million of deferred financing costs written off related to the Senior Secured Credit Facilities and repurchase and cancellation of convertible debentures. This was partially offset by lower interest expense related to the 9.0% Notes that were redeemed in July 2015.

Foreign exchange loss (gain)

Foreign exchange loss increased $49.9 million from the comparable 2015 period primarily due to a $50.1 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The closing U.S. dollar to Canadian dollar exchange rates were 1.29 and 1.25 at June 30, 2016 and 2015, respectively, a decrease of 6.7% as compared to an increase of 7.7% in 2015. The average U.S. dollar to Canadian dollar exchange rates were 1.32 and 1.26 for the six months ended June 30, 2016 and 2015, respectively.

Income tax expense

Income tax benefit for the six months ended June 30, 2016 was $16.8 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.0 million. The primary items impacting the tax rate for the six months ended June 30, 2016 were $5.1 million relating to foreign exchange, $4.6 million relating to a change in the valuation allowance, $4.2 million related to capital gain on intercompany notes and $0.1 million of other permanent differences. These items were partially offset by $18.8 million related to capital loss recognized on tax restructuring.

Income tax benefit for the six months ended June 30, 2015 was $1.7 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.8 million. The primary items impacting the tax rate for the six months ended June 30, 2015 were $4.1 million relating to foreign exchange, $4.0 million relating to operating in higher tax rate jurisdictions, $3.6 million related to tax credits, and $0.6 million of other permanent differences. These items were partially offset by $6.2 million relating to a change in the valuation allowance, and $3.6 million relating to dividend withholding and other taxes.

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Project Operating Performance

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was not material for the three and six months ended June 30, 2016. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in thousands of Net MWh.

	Generation(1)			
	Three months ended	June 30,		
(in thousands of Net MWh)	2016	2015	% change 2016 vs. 2015	
Segment				
East U.S.	616.7	646.1	(4.6)	%
West U.S.	360.1	417.7	(13.8)	%
Canada	501.1	456.7	9.7	%
Total	1,477.9	1,520.5	(2.8)	%

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended June 30, 2015. The Wind Projects were sold in June 2015.

Three months ended June 30, 2016 compared with three months ended June 30, 2015

Aggregate power generation for the three months ended June 30, 2016 decreased 2.8% from the comparable 2015 period primarily due to:

· decreased generation in the West U.S. segment primarily due to a 78.0 net MWh decrease in generation at Frederickson due to an outage in the second quarter of 2016, partially offset by a 14.0 net MWh increase in generation at Naval Training Center due to higher availability.

These decreases were partially offset by:

·

increased generation in the Canada segment was primarily due to a 50.1 net MWh increase in generation at Mamquam due to higher water flow, partially offset by a 6.2 MWh decrease in generation at Nipigon due to the maintenance outage.

	Generation(1)			
	Six months ended June 30,			
			% change	
(in thousands of Net MWh)	2016	2015	2016 vs. 2015	
Segment				
East U.S.	1,283.6	1,299.4	(1.2)	%
West U.S.	702.7	767.4	(8.4)	%
Canada	1,044.9	973.7	7.3	%
Total	3,031.2	3,040.5	(0.3)	%

(1) Excludes the Wind Projects, which were designated discontinued operations for the three and six months ended June 30, 2015. The Wind Projects were sold in June 2015.

Six months ended June 30, 2016 compared with six months ended June 30, 2015

Aggregate power generation for the six months ended June 30, 2016 decreased 0.3% from the comparable 2015 period primarily due to:

· decreased generation in the West U.S. segment primarily due to a 76.7 net MWh decrease in generation at

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Manchief due to lower dispatch and a 10.8 MWh decrease in generation at North Island due to the maintenance outage, partially offset by a 16.8 MWh increase in generation at Frederickson due to an outage in the second quarter of 2016.

This decrease was partially offset by:

· increased generation in the Canada segment primarily due to a 71.4 net MWh increase in generation at Mamquam due to higher water flows; and

· increased generation in the East U.S. segment primarily due to a 34.3 net MWh increase in generation at Morris due to higher demand and lower gas prices and a 20.8 MWh increase in generation at Curtis Palmer due to higher water flow, partially offset by a 15.7 MWh decrease in generation at Selkirk due to lower demand.

	Availability(1) Three months ended June 30,		
	2016	2015	% change 2016 vs. 2015
Segment			
East U.S.	92.7 %	94.5 %	(1.9) %
West U.S.	90.6 %	81.8 %	10.8 %
Canada	95.1 %	94.1 %	1.1 %
Weighted average	92.7 %	91.0 %	1.9 %

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended June 30, 2015. The Wind Projects were sold in June 2015.

Three months ended June 30, 2016 compared with three months ended June 30, 2015

Weighted average availability for the three months ended June 30, 2016 increased 1.9% from the comparable 2015 period primarily due to:

· increased availability in the West U.S. segment primarily due to Manchief and Naval Training Center, which underwent maintenance outages in the comparable 2015 period; and

· increased availability in the Canada segment primarily due to Calstock, which underwent an outage during the comparable period in 2015.

These increases were partially offset by:

· decreased availability in the East U.S. segment primarily due to Selkirk, which underwent an extended scheduled maintenance outage from March 2016.

	Availability(1) Six months ended June 30,					
	2016		2015		% change 2016 vs. 2015	
Segment						
East U.S.	95.9	%	96.2	%	(0.3)	%
West U.S.	90.1	%	89.5	%	0.7	%
Canada	97.3	%	95.5	%	1.9	%
Weighted average	94.6	%	94.2	%	0.4	%

(2) Excludes the Wind Projects, which were designated as discontinued operations for the three and six months ended June 30, 2015. The Wind Projects were sold in June 2015.

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Six months ended June 30, 2016 compared with six months ended June 30, 2015

Weighted average availability for the six months ended June 30, 2016 increased 0.4% from the comparable 2015 period primarily due to:

- increased availability in the Canada segment primarily due to Mamquam, which underwent an outage during the comparable period in 2015.

Supplementary Non GAAP Financial Information

The key measurement we use to evaluate the results of our business is Project Adjusted EBITDA. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We believe that Project Adjusted EBITDA is a useful measure of financial results at our projects because it excludes non-cash impairment charges, gains or losses on the sale of assets and non-cash mark-to-market adjustments, all of which can affect year-to-year comparisons. Project Adjusted EBITDA is before corporate overhead expense. The most directly comparable GAAP measure to Project Adjusted EBITDA is Project income. A reconciliation of Net (loss) income to Project income and to Project Adjusted EBITDA is provided under "Project Adjusted EBITDA" below. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

Project Adjusted EBITDA

	Three months ended			Six months ended		
	June 30,		$ change 2016 vs	June 30,		$ change 2016 vs
	2016	2015	2015	2016	2015	2015
Net (loss) income	$ (16.3)	$ 13.6	$ (29.9)	$ (29.3)	$ 25.8	$ (55.1)
Net Income from discontinued operations, net of tax	-	33.6	(33.6)	—	21.1	(21.1)
Income tax (benefit) expense	(18.4)	2.9	(21.3)	(16.8)	(1.7)	(15.1)

(Loss) income from continuing operations before income taxes	(34.7)	(17.1)	(17.6)	(46.1)	3.0	(49.1)
Administration	5.8	6.6	(0.8)	11.9	16.0	(4.1)
Interest, net	51.2	24.6	26.6	67.8	50.3	17.5
Foreign exchange loss (gain)	2.6	4.8	(2.2)	22.5	(27.4)	49.9
Other income, net	0.3	(1.7)	2.0	(2.2)	(3.1)	0.9
Project income	$ 25.2	$ 17.2	$ 8.0	$ 53.9	$ 38.8	$ 15.1
Reconciliation to Project Adjusted EBITDA						
Depreciation and amortization	30.4	33.3	(2.9)	60.3	66.1	(5.8)
Interest expense, net	2.9	2.5	0.4	5.4	4.9	0.5
Change in the fair value of derivative instruments	(12.2)	(6.9)	(5.3)	(11.0)	(5.1)	(5.9)
Impairment and other expense	(0.1)	(2.2)	2.1	0.1	(2.2)	2.3
Project Adjusted EBITDA	$ 46.2	$ 43.9	$ 2.3	$ 108.7	$ 102.5	$ 6.2
Project Adjusted EBITDA by segment(1)						
East U.S.	20.9	27.0	(6.1)	51.2	53.7	(2.5)
West U.S.	14.5	5.7	8.8	22.0	15.6	6.4
Canada	10.9	11.6	(0.7)	35.7	35.4	0.3
Un-Allocated Corporate	(0.1)	(0.4)	0.3	(0.2)	(2.2)	2.0
Total	46.2	43.9	2.3	108.7	102.5	6.2

(1) Excludes the Wind Projects, which were designated a component of discontinued operations for the three and six months ended June 30, 2015. The Wind Projects were sold in June 2015.

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East U.S.

The following table summarizes Project Adjusted EBITDA for our East U.S. segment for the periods indicated:

	Three months ended June 30,		
	2016	2015	% change 2016 vs. 2015
East U.S.			
Project Adjusted EBITDA	$ 20.9	$ 27.0	(23) %

Three months ended June 30, 2016 compared with three months ended June 30, 2015

Project Adjusted EBITDA for the three months ended June 30, 2016 decreased $6.1 million from the comparable 2015 period primarily due to decreased Project Adjusted EBITDA of:

- $3.1 million at Curtis Palmer due to lower water flows than the comparable 2015 period;
- $1.4 million at Morris due to lower fuel optimization from mild weather and increased maintenance expense than the comparable 2015 period; and
- $0.6 million at Chambers due to lower energy and steam revenues resulting from decreased dispatch than in the comparable 2015 period.

	Six months ended June 30,		
	2016	2015	% change 2016 vs. 2015
East U.S.			
Project Adjusted EBITDA	$ 51.2	$ 53.7	(5) %

Six months ended June 30, 2016 compared with six months ended June 30, 2015

Project Adjusted EBITDA for the six months ended June 30, 2016 decreased $2.5 million from the comparable 2015 period primarily due to decreased Project Adjusted EBITDA of:

· $1.4 million at Kenilworth due to the maintenance outage in May 2016;

· $0.9 million at Morris due to lower gas prices than the comparable 2015 period;

· $0.7 million at Chambers due to lower energy and steam revenues resulting from decreased dispatch than the comparable 2015 period; and

· $0.7 million at Selkirk due to lower merchant revenues due to lower capacity, offset by lower fuel costs.

These decreases were partially offset by an increase in Project Adjusted EBITDA of:

· $2.0 million at Curtis Palmer due to higher water flow than the comparable 2015 period.

West U.S.

The following table summarizes Project Adjusted EBITDA for our West U.S. segment for the periods indicated:

	Three months ended June 30,		
			% change
	2016	2015	2016 vs 2015
West U.S.			
Project Adjusted EBITDA	$ 14.5	$ 5.7	154 %

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Three months ended June 30, 2016 compared with three months ended June 30, 2015

Project Adjusted EBITDA for the three months ended June 30, 2016 increased $8.8 million from the comparable 2015 period primarily due to increased Project Adjusted EBITDA of:

- $8.3 million at Manchief due to lower maintenance expense. Manchief underwent a maintenance overhaul in the comparable 2015 period.

	Six months ended June 30,		
	2016	2015	% change 2016 vs 2015
West U.S.			
Project Adjusted EBITDA	$ 22.0	$ 15.6	41 %

Six months ended June 30, 2016 compared with six months ended June 30, 2015

Project Adjusted EBITDA for the six months ended June 30, 2016 increased $6.4 million from the comparable 2015 period primarily due to increased Project Adjusted EBITDA of:

- $7.9 million at Manchief due to lower maintenance expense. Manchief underwent a maintenance overhaul in the comparable 2015 period.

This increase was partially offset by a decrease in Project Adjusted EBITDA of:

- $0.9 million at Naval Station due to $0.9 million of higher maintenance expense related to a hot gas path maintenance outage.

Canada

The following table summarizes Project Adjusted EBITDA for our Canada segment for the periods indicated:

	Three months ended June 30,		
			% change
	2016	2015	2016 vs. 2015
Canada			
Project Adjusted EBITDA	$ 10.9	$ 11.6	(6) %

Three months ended June 30, 2016 compared with three months ended June 30, 2015

Project Adjusted EBITDA for the three months ended June 30, 2016 decreased $0.7 million from the comparable 2015 period primarily due to decreases in Project Adjusted EBITDA of:

· $1.1 million at Kapuskasing due to a maintenance outage in June 2016;

· $0.9 million at North Bay due to a maintenance outage in June 2016; and

· $0.6 million at William Lake due to lower energy revenue.

These decreases were partially offset by an increase in Project Adjusted EBITDA of:

· $2.0 million at Mamquam due to higher water flows than the comparable 2015 period.

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	Six months ended June 30,		
			% change
	2016	2015	2016 vs. 2015
Canada			
Project Adjusted EBITDA	$ 35.7	$ 35.4	1 %

Six months ended June 30, 2016 compared with six months ended June 30, 2015

Project Adjusted EBITDA for the six months ended June 30, 2016 increased $0.3 million from the comparable 2015 period primarily due to an increase in Project Adjusted EBITDA of:

· $3.1 million at Mamquam due to higher water flow than the comparable 2015 period.

This increase was partially offset by decreases in Project Adjusted EBITDA of:

· $1.4 million at Kapuskasing due to a maintenance outage in June 2016;

· $0.8 million at North Bay due to a maintenance outage in June 2016; and

· $0.6 million at William Lake due to lower energy revenue.

Un allocated Corporate

The following table summarizes Project Adjusted EBITDA for our Un allocated Corporate segment for the periods indicated:

	Three months ended June 30,		
			% change
	2016	2015	2016 vs. 2015
Un-allocated Corporate			
Project Adjusted EBITDA	$ (0.1)	$ (0.4)	(75) %

Three months ended June 30, 2016 compared with three months ended June 30, 2015

Project Adjusted EBITDA for the three months ended June 30, 2016 did not change materially.

	Six months ended June 30,		
	2016	2015	% change 2016 vs. 2015
Un-allocated Corporate Project Adjusted EBITDA	$ (0.2)	$ (2.2)	(91) %

Six months ended June 30, 2016 compared with six months ended June 30, 2015

Project Adjusted EBITDA for the six months ended June 30, 2016 increased $2.0 million from the comparable 2015 period primarily due to an increase in Project Adjusted EBITDA of:

- $0.9 million of lower compensation expense from headcount reductions and $1.0 million in decreased development and administrative costs.

Project Adjusted EBITDA excludes the Wind Projects, which are designated as discontinued operations for the three and six months ended June 30, 2015. Project Adjusted EBITDA for the Wind Projects was $14.8 million and $28.1 million for the three and six months ended June 30, 2015, respectively.

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Liquidity and Capital Resources

	June 30, 2016	December 31, 2015
Cash and cash equivalents	$ 154.2	$ 72.4
Restricted cash	14.3	15.2
Total	168.5	87.6
Revolving credit facility availability	97.2	106.0
Total liquidity	$ 265.7	$ 193.6

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. Our future liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from December 31, 2017 (at our North Bay and Kapuskasing projects) to December 2037. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements or may elect to operate certain facilities in the merchant market upon expiration of their PPAs. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, repurchase of common shares and other allocation of available cash. See "Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities or fund our operations" in our Annual Report on Form 10 K for the year ended December 31, 2015.

We expect to reinvest approximately $53.2 million in our portfolio in the form of project capital expenditures and maintenance expenses in 2016. Such investments are generally paid at the project level. See "—Capital and Major Maintenance Expenditures" in our Annual Report on Form 10 K for the year ended December 31, 2015. We do not expect any other material or unusual requirements for cash outflows for 2016 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

Consolidated Cash Flow Discussion

The following table reflects the changes in cash flows for the periods indicated:

	Six months ended June 30, 2016	2015	Change
Net cash provided by operating activities	$ 53.7	$ 53.4	$ 0.3
Net cash provided by investing activities	3.6	324.8	(321.2)
Net cash provided (used) in financing activities	24.5	(94.4)	118.9

Operating Activities

Cash flow from our projects may vary from period to period based on working capital requirements and the operating performance of the projects, as well as changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

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For the six months ended June 30, 2016, the net increase in cash flows from operating activities of $0.3 million was primarily the result of the following:

- Increase in Project Adjusted EBITDA – Project Adjusted EBITDA increased by $6.2 million primarily due to lower maintenance expense than the comparable 2015 period; and

- Decrease in interest payments – We made $11.6 million in lower interest payments than the comparable 2015 period primarily due to the redemption of the 9.0% High Yield Notes in July 2015.

This increase was partially offset by a decrease in net cash provided by operating activities primarily the result of the following:

- Sale of Wind Projects – in the first quarter of 2015, the Wind Projects, which were sold in June 2015, provided $21.9 million of operating cash flows.

Investing Activities

Cash flow from investing activities includes changes in restricted cash. Restricted cash fluctuates from period to period in part because certain of our non recourse project level financing arrangements require all operating cash flow from the project to be deposited in restricted accounts and then released at the time that principal payments are made and project level debt service coverage ratios are met. As a result, the timing of principal payments on certain of our project level debt causes significant fluctuations in restricted cash balances, which typically benefits investing cash flow in the second and fourth quarters of the year and decreases investing cash flow in the first and third quarters of the year. For the six months ended June 30, 2016, the net decrease in cash flows from investing activities of $321.2 million was primarily the result of the following:

- Sale of Wind Projects – we received $326.3 million of net proceeds from the sale of Wind Projects and the Frontier solar development project in the second quarter of 2015.

This decrease was partially offset by an increase in net cash provided by investing activities primarily the result of the following:

- Reimbursement of construction cost – we received a reimbursement of $4.7 million for the construction project at Morris.

Financing Activities

For the six months ended June 30, 2016, the net increase in cash flows used in financing activities of $118.9 million was primarily the result of the following:

- The New Credit Facilities – we received $679.0 million of net proceeds from issuance of the New Credit Facilities.

This increase was partially offset by decreases in net cash used by financing activities primarily as a result of the following:

- Corporate and project-level debt – we redeemed the Senior Secured Credit Facilities in full for $447.9 million in the second quarter of 2016 and made $54.8 million of principal payments on our corporate and project-level debt; and

- Convertible debenture repayments – we redeemed and cancelled Series A and B convertible debentures, in full, with a payment of $110.7 million with a portion of the proceeds from the New Credit Facilities and also redeemed and cancelled $16.2 million of convertibles debentures under the NCIB during 2016.

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Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2016:

	Maturity Date	Interest Rates		Remaining Principal Repayments	2016	2017	2018	2019	2020	Thereafter
Senior Secured Term Loan Facility(1)(2)	April 2023	6.00 %	- 6.30 %	$ 674.9	$ 35.0	$ 100.0	$ 90.0	$ 65.0	$ 105.0	$ 279.9
Atlantic Power Income LP Note	June 2036	5.95 %		162.6	—	—	—	—	—	162.6
Convertible Debenture(3)	June 2019	5.75 %		105.3	—	—	—	105.3	—	—
Convertible Debenture	December 2019	6.00 %		62.7	—	—	—	62.7	—	—
Total Corporate Debt				$ 1,005.5	$ 35.0	$ 100.0	$ 90.0	$ 233.0	$ 105.0	$ 442.5

(1) In addition to the annual principal payments described herein, the Credit Agreement requires payment of 50% of the excess cash flow of APLP Holdings LP and its subsidiaries. We entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $444.4 million of the $674.9 million outstanding aggregate borrowings at June 30, 2016. See Note 8, Accounting for derivative instruments and hedging activities for further details. The range of interest rates for the Senior Secured Term Loan Facility is based on LIBOR as of June 30, 2016.

(2) The New Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the New Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

(3) In July 2016, we purchased and cancelled $62.7 million principal amount of the debentures.

Project Level Debt

Project level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project level debt generally amortizes during the term of the respective revenue generating contracts of the projects. All project level debt is non recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The following table summarizes the maturities of project level debt. The amounts represent our share of the non recourse project level debt balances at June 30, 2016. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. At August 4, 2016, all of our projects with the exception of Piedmont were in compliance with the covenants contained in project level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but are not callable or subject to acceleration under the terms of their debt agreements. We do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before the project's debt maturity in 2018 at the earliest. See Note 5 to the consolidated financial statements of this Quarterly Report on Form 10-Q, Long term debt—Non Recourse Debt.

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The range of interest rates presented represents the rates in effect at June 30, 2016. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Maturity Date	Range of Interest Rates	Total Remaining Principal Repayments	2016	2017	2018	2019	2020	Therea
onsolidated ojects:									
psilon ower rtners	January 2019	3.40 %	$ 16.5	$ 3.0	$ 6.3	$ 6.5	$ 0.7	$ —	$ —
edmont	August 2018	8.47 %	59.0	2.4	2.5	54.1	—	—	—
adillac	August 2025	6.19 %	28.3	1.3	3.0	3.0	3.1	2.7	15.2
otal onsolidated ojects			103.8	6.7	11.8	63.6	3.8	2.7	15.2
quity ethod ojects:									
hambers(1)	December 2019 and 2023	4.50 % - 5.00 %	42.9		—	—	5.2	7.8	29.9
otal Equity ethod ojects			42.9	—	—	—	5.2	7.8	29.9
otal oject-Level ebt			$ 146.7	$ 6.7	$ 11.8	$ 63.6	$ 9.0	$ 10.5	$ 45.1

(1) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax exempt) Bonds due December 2023, of which our proportionate share is $41.3 million and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is $1.6 million. The above table does not include our $4.2 million proportionate share of issuance premiums.

Uses of Liquidity

Our requirements for liquidity and capital resources, other than operating our projects, consist primarily of principal and interest on our outstanding convertible debentures, senior notes and other corporate and project level debt, funding the repurchase of shares of our common stock (to the extent we choose to pursue any such repurchase), collateral and capital expenditures, including major maintenance and business development costs and dividend payments, if and when declared by our board of directors, to our common shareholders and preferred shareholders of a subsidiary company. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non recourse operating level debt, although we can provide no assurances regarding the availability of public or private financing on acceptable terms or at all.

Capital and Maintenance Expenditures

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On going capital expenditures for assets of this nature are generally not significant because most expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $8.4 million in 2016 (of which $2.0 million was reinvested in the six months ended June 30, 2016) in our portfolio in the form of project capital expenditures and incur $44.8 million of maintenance expenses (of which $23.3 million was incurred in the six months ended June 30, 2016). Such investments are generally paid at the project level. See "—Capital and Major Maintenance Expenditures" in our Annual Report on Form 10 K for the year ended December 31, 2015. We do not expect any other material or unusual requirements for cash outflows for 2016 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

We believe one of the benefits of our diverse fleet is that plant overhauls and other expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to assess maintenance needs. In addition, we utilize predictive and risk based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and maintenance expenses may exceed the projected level in 2016 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

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Scheduled maintenance outages during the six months ended June 30, 2016 occurred at such times that did not materially impact the facilities' availability requirements under their respective PPAs.

Recently Adopted and Recently Issued Accounting Guidance

See Note 1 to the consolidated financial statements in this Quarterly Report on Form 10 Q.

Off Balance Sheet Arrangements

As of June 30, 2016, we had no off balance sheet arrangements as defined in Item 303(a)(4) of Regulation S K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to financial market risk results primarily from fluctuations in interest and currency rates and fuel and electricity prices. There have been no material changes to our market risks as disclosed in our Annual Report on Form 10 K for the fiscal year ended December 31, 2015.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures, as defined in Rules 13a 15(e) and 15d 15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective as of June 30, 2016 as a result of the material weakness that exists in our internal control over financial reporting as previously described in our Annual Report on Form 10-K for the year ended December 31, 2015.

Previously Identified Material Weakness

As of December 31, 2015, Management concluded that our internal control over financial reporting was not effective due to the material weakness identified. Management concluded that the long-lived asset and goodwill impairment tests were not designed effectively to ensure the proper application of U.S. GAAP over (i) the determination of the carrying value of our asset groups and reporting units used in the accounting for long-lived asset recoverability and goodwill impairment test, and (ii) the determination of the long-lived asset and goodwill impairment charges. Specifically, with respect to (i) and (ii), we did not design and maintain effective controls related to determining the carrying value of the asset groups for the purpose of performing the long-lived asset impairment testing as we did not appropriately include the carrying value of goodwill in certain long-lived asset groups in which the asset group is at the same level as the reporting unit. This resulted in an initial conclusion that no long-lived asset impairment should be recorded and also impacted the carrying value of our reporting units for step 1 and step 2 of our goodwill impairment tests. These control deficiencies resulted in misstatements related to goodwill, property, plant and equipment, deferred income taxes and impairment, within the preliminary consolidated financial statements that were corrected prior to the issuance of the Company's consolidated financial statements as of and for the fiscal year ended December 31, 2015.

A material weakness is defined as a deficiency, or combination of deficiencies in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected in a timely manner.

Management's Remediation Plan

Management is actively engaged in the planning for, and implementation of, remediation efforts to address the material weakness identified above. Management intends to take the following actions to address the material weakness:

Re-designing its controls, including the implementation of new controls, relating to the long-lived asset and goodwill impairment analysis, including: (i) enhancing the design and documentation of management review controls in order to enhance the precision at which management review controls operate, (ii) improving the documentation of

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internal control procedures, and (iii) enhancing the evaluation of the components of carrying value and comparison to the requirements of generally accepted accounting principles.

We are in the process of implementing our remediation plan and expect to have the material weakness remediated prior to December 31, 2016.

Changes in Internal Control over Financial Reporting

Other than the material weakness described above, there has been no change in our internal control over financial reporting during the three and six months ended June 30, 2016 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent material errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the control may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to legal proceedings, including securities class actions, from time to time. In particular, we and/or certain of our current and former officers have been named as defendants in various class action lawsuits. Due to the nature of these proceedings, the lack of precise damage claims and the type of claims we are subject to, we are unable to determine the ultimate or maximum amount of monetary liability or financial impact, if any, to us in these legal matters, which unless otherwise specified, seek damages from the defendants of material or indeterminate amounts.

Shareholder class action lawsuits

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. This claim named the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs sought leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserted common law claims for misrepresentation.

The Plaintiffs' motions for leave and certification were heard on May 20-21, 2015.

On July 24, 2015, the Ontario Superior Court of Justice issued a decision denying the Plaintiffs' motion for leave and certification. The Superior Court granted leave to reconstitute a claim for debenture holders but required that there be a debenture holder as plaintiff, that the claim be amended and that the Plaintiffs pay the Defendants partial indemnity costs of responding to the Plaintiffs' motion.

The Plaintiffs appealed the July 24 decision on leave and certification to the Ontario Court of Appeal.

The appeal was subsequently abandoned by the Plaintiffs, and the Ontario action was dismissed by Order dated December 2, 2015, the Defendants agreeing not to claim costs from the Plaintiffs.

The proposed Quebec class action was suspended by the Superior Court of Quebec pending the outcome of the motions for leave and certification of the Ontario action as a class proceeding. On April 19, 2016, the Superior Court of Quebec authorized the discontinuance of the action.

Other than as described above, there were no material changes to legal proceedings disclosed in “Item 3. Legal Proceedings” of our Annual Report on Form 10 K for the year ended December 31, 2015.

ITEM 1A. RISK FACTORS

There were no material changes to the risk factors disclosed in “Item 1A. Risk Factors” of our Annual Report on Form 10 K for the year ended December 31, 2015 (except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10 Q relates to such risk factors (including, without limitation, the matters discussed in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations”). To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2015 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updated to our business strategy, such risk factors should be read in light of such information.

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.1	Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8 K filed on April 13, 2016).
10.2	Securities Pledge Agreement, dated as of April 13, 2016, among Atlantic Power Corporation, Atlantic Power GP II, Inc. and Goldman Sachs Lending Partners LLC as Collateral Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8 K filed on April 13, 2016).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

*Filed herewith.

**Furnished herewith.

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SIGNATURES

Pursuant to the requirements 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: August 8, 2016	Atlantic Power Corporation
	By: /s/ Terrence Ronan
	Name: Terrence Ronan
	Title: Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)