Martinez Alberto R Jr
Form 4
May 10, 2013

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

OMB APPROVAL

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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Martinez Alberto R Jr

(Last) (First) (Middle)

C/O CELSION CORPORATION, 997 LENOX DRIVE, SUITE 100

(Street)

LAWRENCEVILLE, NJ 08648

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
Celsion CORP [CLSN]

3. Date of Earliest Transaction (Month/Day/Year)
05/10/2013

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Celsion Corporation Common Stock	05/10/2013		P		5,000 (1)	A	$ 0.92	165,375	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Martinez Alberto R Jr C/O CELSION CORPORATION 997 LENOX DRIVE, SUITE 100 LAWRENCEVILLE, NJ 08648	X			

Signatures

Timothy J Tumminello, Controller and CAO	05/10/2013
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The Director purchased the shares on the open market.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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For the six month period ended June 30, 2011	**Interest Rate Swaps**	**Natural Gas Swaps**	**Total**
Accumulated OCI balance at December 31, 2010	$ (427)	$ 682	$ 255
Change in fair value of cash flow hedges	658		658
Realized from OCI during the period	(710)	(179)	(889)
Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24

For the six month period ended June 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2009	$ (538)	$ (321)	$ (859)
Change in fair value of cash flow hedges	595		595
Realized from OCI during the period	(431)	501	70
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)

10. Income taxes

The difference between the actual tax benefit of $7.7 million and $6.2 million for the three and six months ended June 30, 2011, respectively, and the expected income tax expense, based on the Canadian enacted statutory rate of 26.5%, of $1.4 million and $3.4 million, respectively is primarily due

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Income taxes (Continued)

to the change in basis of the Idaho Wind assets due to the receipt of the proceeds of the stimulus grant as well as a decrease in the valuation allowance and various other permanent differences.

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Current income tax expense (benefit)	$ 18	$ 1,038	$ (470)	$ 1,075
Deferred tax expense (benefit)	(7,702)	2,580	(5,691)	7,416
Total income tax expense (benefit)	$ (7,684)	$ 3,618	$ (6,161)	$ 8,491

Valuation Allowance

As of June 30, 2011, we have recorded a valuation allowance of $78.4 million. This amount is comprised primarily of provisions against available Canadian and U.S net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

11. Long-Term Incentive Plan

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2011:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2010	600,981	$ 10.28
Granted	153,094	$ 14.18
Forfeited	(101,559)	$ 11.61
Additional shares from dividends	20,302	$ 10.95
Vested and redeemed	(263,523)	$ 9.40
Outstanding at June 30, 2011	409,295	$ 11.85

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. Compensation expense for notional units granted in 2011 is recorded net of estimated forfeitures. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Long-Term Incentive Plan (Continued)

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of June 30, 2011:

Weighted average risk free rate of return	0.39%	0.72%
Dividend yield		7.5%
Expected volatility Company	20.5%	25.9%
Expected volatility peer companies	15.2%	92.7%
Weighted average remaining measurement period		1.26 years

12. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2011. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the six months ended June 30, 2010, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Basic and diluted earnings (loss) per share (Continued)

anti-dilutive. The following table sets forth the diluted net income (loss) and potentially dilutive shares utilized in the per share calculation for the three and six month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Numerator:				
Net income (loss) attributable to Atlantic Power Corporation	$ 13,186	$ 1,445	$ 19,322	$ (4,618)
Add: interest expense for potentially dilutive convertible debentures, net[(1)]	1,931		3,985	
Diluted net income (loss) attributable to Atlantic Power Corporation	15,117	1,445	23,307	(4,618)

(1) The above adjustment for net interest on the potential common shares that would be issued on the conversion of the convertible debentures has been excluded as the impact would be anti-dilutive for the three and six months ended June 30, 2010.

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Denominator:				
Weighted average basic shares outstanding	68,573	60,481	68,116	60,443
Dilutive potential shares:				
Convertible debentures	14,055	11,473	14,430	11,473
LTIP notional units	311	409	427	402
Potentially dilutive shares	82,939	72,363	82,973	72,318
Diluted EPS	$ 0.18	$ 0.02	$ 0.28	$ (0.08)

Potentially dilutive shares from convertible debentures for the three and six-month periods ended June 30, 2010 have been excluded from fully diluted because their impact would be anti-dilutive.

13. Segment and related information

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income 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 use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is included in the table below.

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2011:								
Operating revenues	$ 7,491	$ 20,434	$ 16,844	$ 3,382	$ 0	$ 5,107	$ 0	$ 53,258
Segment assets	207,838	98,152	105,782	37,564	147,572	329,052	83,020	1,008,980
Project Adjusted EBITDA	$ 7,186	$ 11,606	$ 8,424	$ 1,469	$ 4,307	$ 9,862	$ 0	$ 42,854
Change in fair value of derivative instruments		1,145	(297)		200	3,778		4,826
Depreciation and amortization	2,005	4,959	2,290	757	844	6,806		17,661
Interest, net	2,943	282	(2)		1,413	2,452		7,088
Other project (income) expense					201	47		248
Project income	2,238	5,220	6,433	712	1,649	(3,221)		13,031
Interest, net							3,510	3,510
Administration							4,671	4,671
Foreign exchange gain							(535)	(535)
Income (loss) from operations before income taxes	2,238	5,220	6,433	712	1,649	(3,221)	(7,646)	5,385
Income tax expense (benefit)							(7,684)	(7,684)
Net income (loss)	2,238	5,220	6,433	712	1,649	(3,221)	38	13,069

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2010:								
Operating revenues	$ 7,729	$ 19,570	$ 17,842	$ 2,763	$ 0	$ 0	$ 0	$ 47,904
Segment assets	213,904	121,303	115,822	40,620	136,351	131,560	102,964	862,524
Project Adjusted EBITDA	$ 7,062	$ 10,431	$ 7,299	$ 1,002	$ 4,141	$ 8,591	$ 0	$ 38,526
Change in fair value of derivative instruments		597	(1,709)		(207)	1,529		210
Depreciation and amortization	2,095	4,950	2,267	746	839	5,699		16,596
Interest, net	3,096	415	(4)		1,651	939		6,097
Other project (income) expense					204	(122)		82
Project income	1,871	4,469	6,745	256	1,654	546		15,541
Interest, net							2,518	2,518
Administration							3,843	3,843
Foreign exchange loss							4,224	4,224
Other expense, net							(26)	(26)
Income (loss) from operations before income taxes	1,871	4,469	6,745	256	1,654	546	(10,559)	4,982
Income tax expense (benefit)	990						2,628	3,618
Net income (loss)	881	4,469	6,745	256	1,654	546	(13,187)	1,364

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2011:								
Operating revenues	$ 15,135	$ 42,216	$ 33,968	$ 5,902	$ 0	$ 9,702	$ 0	$ 106,923
Segment assets	207,838	98,152	105,782	37,564	147,572	329,052	83,020	1,008,980
Project Adjusted EBITDA	$ 13,756	$ 21,919	$ 16,914	$ 392	$ 9,031	$ 16,835	$ 0	$ 78,847
Change in fair value of derivative instruments		184	(1,862)		(552)	4,272		2,042
Depreciation and amortization	3,979	9,918	4,580	1,514	1,679	13,428		35,098
Interest, net	5,934	595	(5)		2,801	4,003		13,328
Other project (income) expense					400	79		479
Project income	3,843	11,222	14,201	(1,122)	4,703	(4,947)		27,900
Interest, net							7,478	7,478
Administration							8,725	8,725
Foreign exchange gain							(1,193)	(1,193)
Income (loss) from operations before income taxes	3,843	11,222	14,201	(1,122)	4,703	(4,947)	(15,010)	12,890
Income tax expense (benefit)							(6,161)	(6,161)
Net income (loss)	3,843	11,222	14,201	(1,122)	4,703	(4,947)	(8,849)	19,051

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2010:								
Operating revenues	$ 15,373	$ 40,037	$ 34,083	$ 5,632	$ 0	$ 0	$ 0	$ 95,125
Segment assets	213,904	121,303	115,822	40,620	136,351	131,560	102,964	862,524
						3,535		
Project Adjusted EBITDA	$ 14,115	$ 19,802	$ 14,612	$ 2,417	$ 10,129	$ 16,200	$ 0	$ 77,275
Change in fair value of derivative instruments		4,809	6,226		(380)	2,074		12,729
Depreciation and amortization	4,194	9,898	4,536	1,492	1,676	11,186		32,982
Interest, net	6,242	886	(6)		3,327	1,429		11,878
Other project (income) expense					403	(122)		281
Project income	3,679	4,209	3,856	925	5,103	1,633		19,405
Interest, net							5,312	5,312
Administration							7,943	7,943
Foreign exchange gain							2,432	2,432
Other expense, net							(26)	(26)
Income (loss) from operations before income taxes	3,679	4,209	3,856	925	5,103	1,633	(15,661)	3,744
Income tax expense (benefit)	1,739						6,752	8,491
Net income (loss)	1,940	4,209	3,856	925	5,103	1,633	(22,413)	(4,747)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 69% and 14%, respectively, of total consolidated revenues for the three-months ended June 30, 2011 and 77% and 16% for the three-months ended June 30, 2010. Progress Energy Florida and CAISO provide for 70% and 14%, respectively, of total consolidated revenues for the six-months ended June 30, 2011 and 77% and 16% for the six-months ended June 30, 2010. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Related party transactions

On February 28, 2011, we entered into a purchase and sale agreement with an affiliate of ArcLight for the purchase of our lessor interest in the Topsham project. The transaction closed on May 6, 2011 and we received proceeds of $8.5 million, resulting in no gain or loss on the sale.

During 2010, we made short-term loans totaling $22.8 million to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. Member loans will be paid down with a combination of excess proceeds from the federal stimulus grant after repaying the cash grant facility, funds from a third closing for additional debt and project cash flow. The federal stimulus grant was approved in June of 2011 and the funds have been received. The third closing from additional debt is expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as June 30, 2011). During the six-months ended June 30, 2011, we received $1.2 million in interest payments related to the member loans. As of August 10, 2011, $15.5 million of the loans have been repaid.

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by ArcLight. On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15.0 million, to be satisfied by a payment of $6.0 million that was made at the termination date, and additional payments of $5.0 million, $3.0 million and $1.0 million on the respective first, second and third anniversaries of the termination date. The remaining liability associated with the termination fee is recorded at its estimated fair value of $3.8 million at June 30, 2011. The contract termination liability is being accreted to the final amounts due over the term of these payments.

15. Commitments and contingencies

Our Lake project is currently involved in a dispute with Progress Energy Florida over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by Progress. The Lake project has filed a claim against Progress in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. Progress filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of June 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Subsequent event

On July 27, 2011, August 3, 2011 and August 5, 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to economically hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction.

The July 27, 2011 transactions include a forward purchase of $32.0 million at $0.9460 per Cdn$1.00, a call option to purchase $84.7 million at $0.94565 per Cdn$1.00 and a put option to sell $116.7 million at $0.90 per Cdn$1.00. The August 3, 2011 transactions include a forward purchase of $76.0 million at $0.9665 per Cdn$1.00, a call option to purchase $14.5 million at $0.9665 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00. The August 5, 2011 transactions include a forward purchase of $81.2 million at $0.9872 per Cdn$1.00, a call option to purchase $9.3 million at $0.9872 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Quarterly Report on Form 10-Q constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "outlook," "objective," "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "should," "plans," "continue," or similar expressions suggesting future outcomes or events. Examples of such statements in this Quarterly Report on Form 10-Q include, but are not limited to, statements with respect to the following:

- the amount of distributions expected to be received from the projects for the full year 2011 and 2012;
- our expectation of higher operating cash flow in 2012, primarily attributable to increased distributions from Selkirk;
- our expectation of a significant increase in cash distributions from Orlando beginning in 2014;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012;
- the expected resumption of distributions from the holding company on our Chambers project in 2012;
- the expectation of the Piedmont Construction to be completed in late 2012; and
- the expectation to complete the Plan of Arrangement in the fourth quarter.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Quarterly Report on Form 10-Q. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk Factors" included in the filings we make from time to time with the SEC. Our business is both competitive and subject to various risks.

These risks include, without limitation:

- a reduction in revenue upon expiration or termination of power purchase agreements;
- the dependence of our projects on their electricity, thermal energy and transmission services customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- projects not operating according to plan;
- the impact of significant environmental and other regulations on our projects;

increased competition, including for acquisitions;

our limited control over the operation of certain minority owned projects;

the failure to receive, on a timely basis or otherwise, the required approvals by Atlantic Power shareholders, CPILP unitholders and government or regulatory agencies (including the terms of such approvals) for the Plan of Arrangement; and

the risk that a condition to closing of the transaction contemplated by the Arrangement Agreement may not be satisfied.

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

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric capacity and energy prices or cash flows that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this Quarterly Report on Form 10-Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Quarterly Report on Form 10-Q may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10-Q.

These forward-looking statements are made as of the date of this Form 10-Q, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of the financial condition and results of operations of Atlantic Power Corporation should be read in conjunction with the interim consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10-Q.

OVERVIEW

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 MW in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. We sell the capacity and energy from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2011 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects under steam sales agreements to industrial purchasers. The transmission system rights (or "TSRs") we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not a pass-through of fuel costs, we use a financial hedging strategy designed to mitigate a portion of the market price risk of fuel purchases.

We partner with recognized leaders in the independent power industry to operate and maintain our projects, including Caithness Energy, LLC, Power Plant Management Services, Delta Power

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Services and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We completed our initial public offering on the Toronto Stock Exchange (TSX: ATP) in November 2004. Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010.

As of August 10, 2011, we had 68,963,203 common shares, Cdn$45.2 million ($47.5 million) principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$72.4million ($76.1 million) principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 million ($84.6 million) principal amount of 5.60% convertible debentures due June 30, 2017 (the "2010 Debentures" and together with the 2006 and 2009 Debentures, the "Debentures") outstanding. The 2006 Debentures, 2009 Debentures and 2010 Debentures are convertible at any time, at the option of the holder, into 80.645, 76.923 and 55.249, respectively, common shares per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40, Cdn$13.00 and Cdn$18.10, respectively, per common share. Holders of common shares currently receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

RECENT DEVELOPMENTS

On June 20, 2011, Atlantic Power, Capital Power Income L.P. ("CPILP"), CPI Income Services Ltd., the general partner of CPILP, and CPI Investments Inc., a unitholder of CPILP that is owned by EPCOR Utilities Inc. and Capital Power Corporation, entered into the Arrangement Agreement, which provides that Atlantic Power will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to the Plan of Arrangement under the Canada Business Corporations Act. Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, Cdn$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately Cdn$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power, for approximately Cdn$121.0 million which equates to approximately Cdn$2.15 per unit of CPILP. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power and CPILP and certain of its subsidiaries will be terminated (or assigned) in consideration of a payment of Cdn$10.0 million. Atlantic Power or its subsidiaries will assume the management of CPILP and enter into a transitional services agreement with Capital Power for a term of up to 6 to 9 months following the completion of the Plan of Arrangement, which will facilitate the integration of CPILP into Atlantic Power.

The Arrangement Agreement contains customary representations, warranties and covenants. Among these covenants, CPILP and CPI Income Services Ltd. have each agreed not to solicit alternative transactions, except that CPILP may respond to an alternative transaction proposal that constitutes, or would reasonably expect to lead to, a superior proposal, that we have a right to match. In addition, Atlantic Power or CPILP may be required to pay a Cdn$35.0 million fee if the Arrangement Agreement is terminated in certain unlikely circumstances.

The completion of the Plan of Arrangement is subject to the receipt of all necessary court and regulatory approvals in Canada and the United States and certain other closing conditions. Atlantic Power and CPILP currently expect to complete the Plan of Arrangement in the fourth quarter of 2011, subject to receipt of required shareholder/unitholder, court and regulatory approvals and other conditions to the Plan of Arrangement described in the Arrangement Agreement.

On May 6, 2011 we closed the sale of our 50.0% lessor interest in the Topsham project for $8.5 million, resulting in no gain or loss on the sale.

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OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of August10, 2011, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

Project Name	Location (State)	Type	Total MW	Economic Interest[1]	Net MW[2]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	121	Tampa Electric Co.	2018	BBB+
Chambers	New Jersey	Coal	262	40.00%	89	ACE[3]	2024	BBB+
					16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	N/A	California Utilities via CAISO[4]	N/A[5]	BBB+ to A[6]
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013[7]	A1[8]
Selkirk	New York	Natural Gas	345	17.70%[9]	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA
					9	Sherwin Alumina	2020	NR
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2012[10]	BBB+

Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	PNM	2020	BB-
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Piedmont(11)	Georgia	Biomass	54	98.00%	53	Georgia Power	2032	A

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

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

(3) Includes a separate power sales agreement in which the project and Atlantic City Electric ("ACE") share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(4) California utilities pay transmission access charges to the California Independent System Operator, who then pays owners of Transmission system rights, such as Path 15, in accordance with its annual revenue requirement approved every three years by the Federal Energy Regulatory Commission ("FERC").

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

(6) Largest payers of transmission access charges supporting Path 15's annual revenue requirement are Pacific Gas & Electric (BBB+), Southern California Edison (BBB+) and San Diego Gas & Electric (A). The California Independent System Operator imposes minimum credit quality requirements for any participants rated A or better unless collateral is posted per the California Independent System Operator imposed schedule.

(7) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF under the terms of the current agreement.

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

(9) Represents our residual interest in the project after all priority distributions are paid to us and the other partners, which is estimated to occur in 2012.

(10) Entered into a one-year interim agreement in April 2011.

(11) Project currently under construction and is expected to be completed in late 2012.

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Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and six month periods ended June 30, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

(Unaudited) (in thousands of U.S. dollars, except as otherwise stated)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Project revenue				
Auburndale	$ 20,434	$ 19,570	$ 42,216	$ 40,037
Lake	16,844	17,842	33,968	34,083
Pasco	3,382	2,763	5,902	5,632
Path 15	7,491	7,729	15,135	15,373
Other Project Assets	5,107		9,702	
	53,258	47,904	106,923	95,125
Project expenses				
Auburndale	13,787	14,089	30,215	30,133
Lake	10,710	12,810	21,634	24,007
Pasco	2,670	2,507	7,024	4,707
Path 15	2,310	2,762	5,357	5,452
Chambers			1	
Other Project Assets	3,564	116	7,829	173
	33,041	32,284	72,060	64,472
Project other income (expense)				
Auburndale	(1,427)	(1,012)	(779)	(5,695)
Lake	299	1,713	1,867	(6,220)
Pasco				
Path 15	(2,943)	(3,096)	(5,935)	(6,242)
Chambers	1,649	1,654	4,704	5,103
Other Project Assets	(4,764)	662	(6,820)	1,806
	(7,186)	(79)	(6,963)	(11,248)
Total project income				
Auburndale	5,220	4,469	11,222	4,209
Lake	6,433	6,745	14,201	3,856
Pasco	712	256	(1,122)	925
Path 15	2,238	1,871	3,843	3,679
Chambers	1,649	1,654	4,703	5,103
Other Project Assets	(3,221)	546	(4,947)	1,633
	13,031	15,541	27,900	19,405
Administrative and other expenses				
Administration	4,671	3,843	8,725	7,943
Interest, net	3,510	2,518	7,478	5,312
Foreign exchange loss (gain)	(535)	4,224	(1,193)	2,432
Other income, net		(26)		(26)
Total administrative and other expenses	7,646	10,559	15,010	15,661
Income from operations before income taxes	5,385	4,982	12,890	3,744
Income tax expense (benefit)	(7,684)	3,618	(6,161)	8,491
Net income (loss)	13,069	1,364	19,051	(4,747)
Net loss attributable to noncontrolling interest	(117)	(81)	(271)	(129)

Net income (loss) attributable to Atlantic Power Corporation shareholders	$ 13,186	$ 1,445	$ 19,322	$ (4,618)

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Consolidated Overview

We have six reportable segments: Auburndale, Chambers, Lake, Pasco, Path 15 and Other Project Assets. The results of operations are discussed below by reportable segment.

Project income is the primary GAAP measure of our operating results and is discussed in "Project Operations Performance" below. In addition, an analysis of non-project expenses impacting our results is set out in "Administrative and Other Expenses (Income)" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Quantitative and Qualitative Disclosures About Market Risk" for additional information); (2) the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar denominated obligations and; (3) the related deferred income tax expense (benefit) associated with these non-cash items.

Cash available for distribution was $18.0 million and $7.5 million for the three-months ended June 30, 2011 and 2010, respectively and $34.6 million and $25.3 million for the six-months ended June 30, 2011 and 2010, respectively. See "Cash Available for Distribution" in this Form 10-Q for additional information.

Income from operations before income taxes for the three-months ended June 30, 2011 and 2010 was $5.4 million and $5.0 million, respectively and $12.9 million and $3.7 million for the six-months ended June 30, 2011 and 2010, respectively. See "Project Income" below for additional information.

Three months ended June 30, 2011 compared with three months ended June 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $0.7 million to $5.2 million in the three-month period ended June 30, 2011 from income of $4.5 million in the comparable 2010 period is primarily attributable to the annual contractual escalation of capacity payments under the project's PPA, as well as favorable gas transportation cost compared to 2010.

Lake Segment

Project income for our Lake segment decreased $0.3 million to $6.4 million in the three-month period ended June 30, 2011, from income of $6.7 million in the comparable 2010 period. The decrease is primarily attributable to a $1.4 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. This was partially offset by lower fuel expenses attributable to lower prices on natural gas swaps.

Pasco Segment

Project income for our Pasco segment increased $0.4 million to $0.7 million in the three-month period ended June 30, 2011, from project income of $0.3 million in the comparable 2010 period. The increase is due to higher dispatch compared to 2010 of the project.

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Path 15 Segment

Project income for our Path 15 segment increased $0.3 million to $2.2 million in the three-month period ended June 30, 2011 from $1.9 million in the comparable 2010 period due to decreased operation and maintenance costs.

Chambers Segment

The change in project income for our Chambers segment, which is recorded under the equity method of accounting, was not significant in the three-month period ended June 30, 2011 compared to same period in 2010.

Other Project Assets Segment

Project income for our Other Project Assets segment decreased $3.7 million to a project loss of $(3.2) million for the three-month period ended June 30, 2011 compared to project income of $0.5 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with the non-cash change in fair value of interest rate swaps recorded at fair value;
- increased expense at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul;
- reduced revenue at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement;
- the absence of income from Topsham. The project was sold in May 2011;
- project loss at Idaho Wind of $0.7 million which became operational in Q1 2011; offset by
- project income of $1.1 million at Cadillac, which was acquired in December 2010.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $0.9 million to $4.7 million in the three-month period ended June 30, 2011 from $3.8 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction and increases in compensation costs attributable to an increase in corporate office staff levels.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $1.0 million to $3.5 million in the three-month period ended June 30, 2011 from $2.5 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss decreased $4.7 million to a $0.5 million gain in the three-month period ended June 30, 2011 compared to a $(4.2) million loss in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 0.5% during the three-month period ended June 30, 2011, compared to a decrease of 4.6% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange gain recognized during the three-month period ended June 30, 2011 compared to the foreign exchange loss in the comparable 2010 period.

Six months ended June 30, 2011 compared with six months ended June 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $7.0 million to $11.2 million in the six-month period ended June 30, 2011 from income of $4.2 million in the comparable 2010 period is primarily attributable to the $4.6 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. Project revenue at Auburndale increased by $2.1 million in the six-month period ended June 30, 2011 due to favorable energy pricing compared to 2010, as well as the annual contractual escalation of capacity payments. Interest expense on project-level debt decreased by $0.3 million in the six-month period ended June 30, 2011 as compared to the comparable period in 2010.

Lake Segment

Project income for our Lake segment increased $10.3 million to $14.2 million in the six-month period ended June 30, 2011, from income of $3.9 million in the comparable 2010 period. The increase is primarily attributable to the $8.1 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. In addition, fuel costs at Lake decreased due to the lower price on natural gas swaps.

Pasco Segment

Project income for our Pasco segment decreased $2.0 million to a project loss of $(1.1) million in the six-month period ended June 30, 2011, from project income of $0.9 million in the comparable 2010 period. The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components during 2011.

Path 15 Segment

Project income for our Path 15 segment was consistent for the six-month period ended June 30, 2011and 2010.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $0.4 million to $4.7 million in the six-month period ended June 30, 2011 from $5.1 million in the comparable 2010 period. The decrease in project income at Chambers is primarily attributable to lower dispatch compared to 2010.

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Other Project Assets Segment

Project income for our Other Project Assets segment decreased $6.5 million to a project loss of $(4.9) million for the six-month period ended June 30, 2011 compared to project income of $1.6 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with a non-cash change in the fair value of an interest rate swap that is recorded at fair value;

- decreased income at Selkirk due to a planned outage lasting longer than expected that delayed recognition of capacity payments until the third quarter of 2011;

- increased expense at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul;

- reduced revenue at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement;

- the absence of income from Topsham. The project was sold in May 2011;

- project loss at Idaho Wind of $0.6 million which became operational in Q1 2011; offset by

- project income at Cadillac of $1.3 million, which was acquired in December 2010.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $0.8 million to $8.7 million for the six-month period ended June 30, 2011 from $7.9 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction and increased compensation costs attributable to an increase in corporate office staff levels.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $2.2 million to $7.5 million in the six-month period ended June 30, 2011 from $5.3 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss decreased $3.6 million to a $1.2 million gain in the six-month period ended 2011 compared to a $(2.4) million loss in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 3.1% during the six-month period ended June 30, 2011, compared to a decrease of 1.3% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange gain recognized during the six-month period ended June 30, 2011 compared to the foreign exchange loss in the comparable 2010 period.

Supplementary Non-GAAP Financial Information

The key measure we use to evaluate the results of our projects is Cash Available for Distribution. Cash Available for Distribution is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Cash Available for Distribution is a relevant supplemental measure of our

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ability to pay dividends to our shareholders. A reconciliation of net cash provided by operating activities to Cash Available for Distribution is set out below under "Cash Available for Distribution." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service and capital expenditures, and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income 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 use unaudited Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is set out below under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Because Project Adjusted EBITDA and project distributions are key drivers of both the performance of our projects and Cash Available for Distribution, please see the following supplementary unaudited non-GAAP information that summarizes Project Adjusted EBITDA by project and a reconciliation of Project Adjusted EBITDA by project to project distributions actually received by us.

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Project Adjusted EBITDA (in thousands of U.S. dollars):

(unaudited)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Project Adjusted EBITDA by individual segment				
Auburndale	$ 11,606	$ 10,431	$ 21,919	$ 19,802
Lake	8,424	7,299	16,914	14,612
Pasco	1,469	1,002	392	2,417
Path 15	7,186	7,062	13,756	14,115
Chambers	4,307	4,141	9,031	10,129
Total	32,992	29,935	62,012	61,075
Other Project Assets				
Selkirk	3,206	3,526	4,314	7,056
Orlando	1,202	1,870	3,093	3,671
Cadillac	2,644		4,391	
Gregory	956	1,428	1,728	2,283
Idaho Wind	1,246		2,051	
Badger Creek	41	774	801	1,510
Delta Person	443	540	842	904
Koma Kulshan	374	434	434	553
Rollcast	(306)		(773)	
Piedmont	(32)		(61)	
Topsham		548		963
Rumford		1		(7)
Other	88	(530)	15	(733)
Total adjusted EBITDA from Other Project Assets segment	9,862	8,591	16,835	16,200
Total adjusted EBITDA from all Projects	42,854	38,526	78,847	77,275
Depreciation and amortization	17,661	16,596	35,098	32,982
Interest expense, net	7,088	6,097	13,328	11,878
Change in the fair value of derivative instruments	4,826	210	2,042	12,729
Other (income) expense	248	82	479	281
Project income as reported in the statement of operations	$ 13,031	$ 15,541	$ 27,900	$ 19,405

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the six months ended June 30, 2011

	Project Adjusted EBITDA	Repayment of debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 21,919	$ (4,900)	$ (595)	$ (5)	$ (1,619)	$ 14,800
Chambers	9,031	(6,398)	(2,801)		168	
Lake	16,914		5	(447)	2,392	18,864
Pasco	392			(39)	452	805
Path 15	13,756	(3,541)	(5,934)		(2,019)	2,262
Total Reportable Segments	62,012	(14,839)	(9,325)	(491)	(626)	36,731
Other Project Assets						
Selkirk	4,314	(5,354)	(777)	(3)	5,974	4,154
Orlando	3,093		2	(118)	(952)	2,025
Cadillac	4,391	(1,150)	(1,317)	(62)	(662)	1,200
Gregory	1,728	(838)	(231)	(44)	51	666
Idaho Wind	2,051	(33,237)	(1,522)		33,917	1,209
Badger Creek	801		(3)		562	1,360
Delta Person	842	(555)	(120)		(167)	
Koma Kulshan	434				(55)	379
Rollcast	(773)			(4)	777	
Piedmont	(61)				61	
Other	15		(35)	40	180	200
Total Other Project Assets Segment	16,835	(41,134)	(4,003)	(191)	39,686	11,193
Total all Segments	$ 78,847	$ (55,973)	$ (13,328)	$ (682)	$ 39,060	$ 47,924

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the six months ended June 30, 2010

	Project Adjusted EBITDA	Repayment of debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 19,802	$ (4,900)	$ (886)	$ (8)	$ (1,008)	$ 13,000
Chambers	10,129	(6,026)	(3,327)	(34)	(742)	
Lake	14,612		6	(1,004)	748	14,362
Pasco	2,417			(467)	380	2,330
Path 15	14,115	(3,740)	(6,242)		181	4,314
Total Reportable Segments	61,075	(14,666)	(10,449)	(1,513)	(441)	34,006
Other Project Assets						
Selkirk	7,056	(4,657)	(1,181)	(309)	(909)	
Orlando	3,671		1	(66)	(1,706)	1,900
Gregory	2,283	(823)	(112)	(39)	(443)	866
Badger Creek	1,510		(7)		138	1,641
Delta Person	904	(1,023)	(137)		256	
Koma Kulshan	553				(206)	347
Rumford	(7)				7	
Topsham	963					963
Other	(733)		7	(40)	792	26
Total Other Project Assets Segment	16,200	(6,503)	(1,429)	(454)	(2,071)	5,743
Total all Segments	$ 77,275	$ (21,169)	$ (11,878)	$ (1,967)	$ (2,512)	$ 39,749

Project Operations Performance Three months ended June 30, 2011 compared with three months ended June 30, 2010

Aggregate Project Adjusted EBITDA increased $4.4 million to $42.9 million in the three-month period ended June 30, 2011 from $38.5 million in the comparable 2010 period and included the following factors:

project Adjusted EBITDA of $2.6 million at Cadillac, which was acquired in December 2010;

project Adjusted EBITDA of $1.2 million at Idaho Wind, which became operational in the first quarter of 2011;

increased Project Adjusted EBITDA of $1.2 million at Auburndale due to the annual contractual escalation of capacity payments, as well as favorable gas transportation costs;

increased Project Adjusted EBITDA of $1.1 million at Lake due to decreased fuel costs attributable to the lower prices on natural gas swaps; offset by decreased Project Adjusted EBITDA of $0.7 million at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement in April 2011;

decreased Project Adjusted EBITDA of $0.7 million at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul in 2011; and

decreased Project Adjusted EBITDA of $0.5 million at Topsham. The project was sold in May 2011.

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Aggregate power generation for projects in operation for the three-months ended June 30, 2011 was 8.8% greater than the three-month period ended June 30, 2010. Generation during the three-month period ended June 30, 2011 compared to the comparable 2010 period was favorably impacted primarily by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk and Pasco. The favorable variance was partially offset by lower generation at Chambers and Badger Creek due to reduced dispatch, and at Lake which had no off-peak deliveries and a planned major maintenance outage at Orlando in 2011.

The project portfolio achieved a weighted average availability of 95.5% for the three-month period ended June 30, 2011 compared to 95.2% in the 2010 period. The increase in portfolio availability for the three-month period ended June 30, 2011 versus the prior period was primarily due to a planned outage at Selkirk completed in 2010 offset by outages at Orlando and Badger Creek in 2011. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Project Operations Performance Six months ended June 30, 2011 compared with six months ended June 30, 2010

Aggregate Project Adjusted EBITDA increased $1.6 million to $78.9 million in the six-month period ended June 30, 2011 from $77.3 million in the comparable 2010 period and included the following factors:

- project Adjusted EBITDA of $4.4 million at Cadillac, which was acquired in December 2010;
- increased Project Adjusted EBITDA of $2.3 million at Lake due to decreased fuel costs attributable to the lower price on natural gas swaps;
- project Adjusted EBITDA of $2.1 million at Idaho Wind, which became operational in the first quarter of 2011;
- increased Project Adjusted EBITDA of $2.1 million at Auburndale due to the annual contractual escalation of capacity payments and increased dispatch; offset by
- decreased Project Adjusted EBITDA of $2.7 million at Selkirk due to lower capacity revenue. A planned outage was longer than expected and resulted in a delay in recognition of capacity payments until the third quarter of 2011;
- decreased Project Adjusted EBITDA of $2.0 million at Pasco primarily due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine blades during a maintenance outage;
- decreased Project Adjusted EBITDA of $1.1 million at Chambers attributable lower dispatch;
- decreased Project Adjusted EBITDA of $1.0 million at Topsham. The project was sold in May 2011;
- decreased Project Adjusted EBITDA of $0.7 million at Badger Creek primarily attributable to lower capacity payments under the new one year interim power purchase agreement in April 2011;
- decreased Project Adjusted EBITDA of $0.6 million at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul in 2011;

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decreased Project Adjusted EBITDA of $0.6 million at Gregory due to lower dispatch and higher fuel costs; and

decreased Project Adjusted EBITDA of $0.4 million at Path 15 due to higher operation and maintenance costs.

Aggregate power generation for projects in operation for the six-months ended June 30, 2011 was 4.6% greater than the six-month period ended June 30, 2010. Generation during the six-month period ended June 30, 2011 was favorably impacted primarily by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk. The favorable variance was partially offset by lower generation at Chambers and Badger Creek due to reduced dispatch and a planned major maintenance outage at Orlando in 2011 and increased generation at Lake associated with off-peak energy sales in 2010.

The project portfolio achieved a weighted average availability of 94.6% for the six-month period ended June 30, 2011 compared to 96.7% in the 2010 period. The decrease in portfolio availability for the six-month period ended June 30, 2011 versus the prior period was primarily due to planned outages at Badger Creek, Chambers and Selkirk and a forced outage at Delta-Person. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Cash Flow from Operating Activities

Our cash flow from the projects may vary from year to year based on, among other things, changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market or re-contracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the projects. 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.

Cash flow from operating activities increased by $8.7 million for the six-month period ended June 30, 2011 over the comparable period in 2010. The changes from the prior period are partially attributable to the changes in Project Adjusted EBITDA described above, the release of $4.2 million of previously restricted cash at our equity accounted Selkirk project, as well as changes in working capital at both consolidated and unconsolidated affiliates.

Cash Flow from Investing Activities

Cash flow from investing activities includes restricted cash. Restricted cash fluctuates from period to period in part because non-recourse project-level financing arrangements typically 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 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.

Cash flows used in investing activities for the six-month period ended June 30, 2011 were $24.8 million compared to cash flows used in investing activities of $1.9 million for the comparable 2010 period. We invested $42.4 million for the construction-in-progress for our Piedmont biomass project offset by the repayment of $15.5 million from our related party loan to Idaho Wind.

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Cash Flow from Financing Activities

Cash used in financing activities for the six-month period ended June 30, 2011 resulted in a net outflow of $18.8 million compared to a net outflow of $20.7 million for the same period in 2010. The change from the comparable period is primarily attributable to a $6.7 million increase in dividends paid due to a higher number of common shares outstanding to the comparable period in 2010. Since the year ended December 31, 2010, Cdn$17.2 million of convertible debentures have converted to common stock. In addition, we issued common shares in a public offering in October 2010. The increase in dividends is partially offset by proceeds of $29.9 million of project-level debt related to our Piedmont biomass project.

Cash Available for Distribution

Holders of our common shares receive monthly cash dividends at an annual rate of Cdn$1.094 per share. Total dividends paid to shareholders for the three and six-month periods ended June 30, 2011 increased over the respective prior year amounts as a result of (i) increases in the value of the Canadian dollar, which is the currency in which the dividends are paid; and (ii) a higher number of common shares outstanding in the 2011 periods as a result of the conversion of convertible debentures into common shares and the issuance of vested shares from our long-term incentive plan. This increase in dividends paid is generally offset by realized gains on our foreign currency forward contracts, which are included in cash flows from operating activities. See "Foreign Currency Exchange Rate Risk" in Item 3 of this Form 10-Q for additional information about our foreign currency forward contracts. The payout ratio for the three-month periods ended June 30, 2011 and 2010 was 109% and 212%, respectively and 111% and 125% for the six-month periods ended June 30, 2011 and 2010, respectively.

The table below presents our calculation of cash available for distribution for the three and six-month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
(unaudited)				
(in thousands of U.S. dollars, except as otherwise stated)	**2011**	**2010**	**2011**	**2010**
Cash flows from operating activities	$ 24,368	$ 15,139	$ 44,715	$ 35,978
Project-level debt repayments	(6,941)	(6,441)	(10,341)	(9,141)
Purchases of property, plant and equipment[(1)]	(238)	(1,201)	(546)	(1,520)
Transaction costs[(2)]	768		768	
Cash Available for Distribution[(3)]	17,957	7,497	34,596	25,317
Total dividends to shareholders	19,550	15,913	38,542	31,714
Payout ratio	109%	212%	111%	125%
Expressed in Cdn$				
Cash Available for Distribution	17,376	7,710	33,793	26,187
Total dividends to shareholders	18,763	16,556	37,386	33,083

(1) Excludes construction-in-progress related to our Piedmont biomass project.

(2) Represents business development costs associated with the CPILP acquisition.

(3) Cash Available for Distribution is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information".

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Outlook

Based on our actual performance to date and projections for the remainder of the year, we continue to expect to receive distributions from our projects in the range of $80 million to $90 million for the full year 2011. We expect overall levels of operating cash flows in 2011 to be improved over actual 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and Cadillac, and a slightly lower payment under the management termination agreement are expected to be partially offset by the one-time cash tax refund of $8.0 million received in 2010. In 2012, additional increases in distributions from projects are expected to further increase operating cash flow compared to 2011. The most significant factor in the expected higher operating cash flow in 2012 is increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following items comprise the most significant increases in projected 2011 project distributions compared to 2010:

- lower fuel costs at the Lake project;
- resumption of distributions from the Selkirk project;
- annual increase in contractual capacity payments from the Auburndale and Lake projects; and
- distributions from the recently acquired Cadillac and Idaho Wind projects.

In 2010, the following five projects comprised approximately 90% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2011, we expect these same five projects to contribute approximately 85% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2011 and beyond:

Lake

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA in July 2013 that are not passed through its PPAs. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas expected to be purchased at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2013, but do not intend to execute additional hedges at Lake for 2011 and 2012 because our natural gas exposure for those years is already substantially hedged.

The variable energy revenues in the Lake project's PPA are indexed, in part, to the price of coal consumed by a specific utility plant in Florida, the Crystal River facility. The components of this coal price are proprietary to the utility, but we believe that the utility purchases coal for that plant under a combination of short to medium term contracts and spot market transactions.

Coal prices used in the energy revenue component of the projected distributions from the Lake project incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions change by approximately $1.0 million for every $0.25/Mmbtu change in the projected price of coal.

We expect to receive distributions from the Lake project of approximately $30 million to $34 million in both 2011 and 2012. The increases in 2011 and 2012 over the $28.8 million of distributions in 2010 are primarily due to higher contractual capacity payments and lower hedged and unhedged natural gas prices than in 2010.

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Auburndale

Based on the current forecast, we expect distributions from Auburndale of $25 million to $27 million per year from 2011 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2011 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to the costs of coal consumed at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the project's gas supply contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. The 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in 2012 and 2013.

Orlando

The PPA at the Orlando project extends through 2023. However, the project's natural gas supply agreement expires in 2013. Currently projected market prices for natural gas following the expiration of the current supply agreement are lower than the price of natural gas currently being purchased under the project's gas contract. As a result, we expect a significant increase in cash distributions from the Orlando project beginning in 2014. We have been executing a hedging strategy to reduce the market price risk associated with expected natural gas requirements at Orlando in 2014 and beyond. See "Item 3. Quantitative and Qualitative Disclosures About Market Risks" in this Form 10-Q for further details.

Liquidity and Capital Resources

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion of the cash received from project distributions is used to pay dividends to our shareholders and interest on our outstanding convertible debentures. 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.

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.

Other than the capital requirements stated below for the CPILP acquisition, we do not expect any additional material or unusual requirements for cash outflows for 2011 for capital expenditures or other required investments. We have contributed approximately $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $59.0 million of this amount was contributed in the fourth quarter of 2010 and the remaining balance was paid in the quarter ending March 31, 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2011. See "Outlook" above for information about changes in expected distributions from our projects in 2011 and beyond.

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We intend to finance the cash portion of the purchase price for the transaction with CPILP by issuing up to approximately Cdn$200.0 million of equity and up to approximately $425.0 million of debt through public and private offerings. However, in the event that such financing is not available on terms satisfactory to us, we have received a commitment letter, evidencing the commitment of a Canadian chartered bank and another financial institution to structure, arrange, underwrite and syndicate a senior secured credit facility consisting of a Tranche B Facility in the amount of $625 million, subject to the terms and conditions set forth therein.

Credit facility

We maintain a credit facility with a capacity of $100 million, $50 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

The credit facility bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.5% and 3.35% that varies based on the credit statistics of one of our subsidiaries. As of June 30, 2011, the applicable margin was 1.5%. As of June 30, 2011, $48.6 million were issued in letters of credit, but not drawn, to support contractual credit requirements at eight of our projects.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on the cash flow coverage ratios and also require us to report indebtedness ratios to our lenders. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures. In 2009 the holders agreed to change the rate to 6.50% and extend the maturity date to 2014. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures have a maturity date of October 31, 2014 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. Through August 10, 2011, a cumulative Cdn$14.5 million of the 2006 Debentures have been converted to 1.2 million common shares. As of August 10, 2011 the 2006 Debentures balance is Cdn$45.2 million ($47.5 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. Through August 10, 2011, a cumulative Cdn$13.9million of the 2009 Debentures have been converted to 1.1 million common shares. As of August 10, 2011 the 2009 Debentures balance is Cdn$72.4 million ($76.1 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately

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Cdn$18.10 per common share. As of August 10, 2011 the 2010 debentures balance is Cdn$80.5 million ($84.6 million).

Project-level debt

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, 2011 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. 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. As of June 30, 2011, the covenants at the Delta-Person project and at Epsilon Power Partners are temporarily preventing those subsidiaries from making cash distributions to us. We expect to resume receiving distributions from Delta-Person and Epsilon Power Partners in 2012. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the six-month period ended June 30, 2011, we have contributed approximately $0.5 million to Epsilon Power Partners for debt service payments on the holding company debt but do not anticipate any additional required contributions to Epsilon.

The range of interest rates presented represents the rates in effect at June 30, 2011.

	Range of Interest Rates	Total Remaining Principal Repayments	2011	2012	2013	2014	2015	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 35,732	$ 750	$ 1,500	$ 3,000	$ 5,000	$ 5,750	$ 19,732
Piedmont[1]	5.20%	29,891		29,891				
Path 15	7.9% - 9.0%	150,327	4,446	8,667	9,402	8,065	8,749	110,998
Auburndale	5.10%	16,800	4,900	7,000	4,900			
Cadillac	6.02% - 8.0%	41,381	1,150	3,791	2,400	2,000	2,500	29,540
Total Consolidated Projects		274,131	11,246	50,849	19,702	15,065	16,999	160,270
Equity Method Projects:								
Chambers	0.9% - 7.0%	69,398	5,647	12,176	10,783	5,780	5,213	29,799
Delta-Person	2.1%	9,966	575	1,212	1,300	1,394	1,495	3,990
Selkirk	9.0%	11,439	5,594	5,845				
Gregory	1.8% - 7.5%	13,510	1,342	1,399	2,007	2,170	2,268	4,324
Idaho Wind[2]	5.2% - 13.3%	50,703	8,429	1,848	1,892	2,049	2,136	34,349
Total Equity Method Projects		155,016	21,587	22,480	15,982	11,393	11,112	72,462
Total Project-Level Debt		$ 429,147	$ 32,833	$ 73,329	$ 35,684	$ 26,458	$ 28,111	$ 232,732

(1) The Piedmont debt outstanding is the inception to date balance on the construction debt funded by the related bridge loan. The terms of the Piedmont project-level debt refinancing include an $82.0 million construction and term loan and a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations. The $51.0 million bridge loan will be repaid in 2012 and repayment of the expected $82.0 million term loan will commence in 2013.

(2) The Idaho Wind project-level credit facility is composed of two tranches, which include a $157.5 million construction loan that was converted to a 17-year term loan upon commercial operations, and a $83.2 million cash grant facility which was repaid in June with federal stimulus grant proceeds after completion of construction, The remaining costs of the project were funded with a combination of equity from the owners

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and member loans from affiliates of Atlantic Power and GE Energy Financial Services. As of June 30, 2011, our share of total debt outstanding for Idaho Wind was $43.4 million, and our share of the member loans was $7.3 million. Member loans will be paid down with a combination of funds from a third closing for additional debt and project cash flow.

Restricted cash

The projects generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. At June 30, 2011, restricted cash at the consolidated projects totaled $21.0 million.

Capital Expenditures

Capital expenditures for the projects are generally made 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 projects in which we have investments generally consist of large capital assets that have established commercial operations. Ongoing capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

In 2011, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is slightly higher than in 2010. During the second quarter of 2011, Badger Creek replaced the combustor section of its gas turbine, the cost of which was covered under the operations and maintenance fee to the project's operator. Orlando undertook a scheduled major overhaul of its gas turbine and a major overhaul of its steam turbine in the second quarter. A substantial portion of Orlando's outage costs are paid through monthly payments under the project's long-term maintenance agreement with Alstom Power. Lake took two planned outages in the second quarter to replace one of its gas turbines and a portion of the other with temporary engine components available under Lake's lease engine agreement with GE, which permits Lake to install replacement engines while the project's components are being repaired. The cost of the repairs to Lake's engines is expected to be covered under the services agreement with GE that provides for unplanned maintenance.

In the six-month period ended June 30, 2011, we incurred approximately $45.6 million in capital expenditures for the construction of our Piedmont biomass project. For the remainder of 2011, we expect to incur approximately $62.5 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million. The project is being funded with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation.

Off-Balance Sheet Arrangements

As of June 30, 2011, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions.

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by generally passing through changes in fuel prices to the buyer of the energy.

The Lake project's operating margin is exposed to changes in the market price of natural gas until the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

We have executed a strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale by periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps at Lake and Auburndale, through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, these natural gas swap hedges were de-designated and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

In 2011, projected cash distributions at Auburndale would change by approximately $0.5 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project. In 2011, projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

Coal prices used in the revenue component of the projected distributions from the Lake and Auburndale projects incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions from Lake and Auburndale combined would change by approximately $2.4 million for every $0.25/Mmbtu change in the projected price of coal.

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The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of June 30, 2011 and August 10, 2011:

	2011	2012	2013
Portion of gas volumes currently hedged:			
Lake:			
Contracted			
Financially hedged	78%	90%	83%
Total	78%	90%	83%
Auburndale:			
Contracted	80%	0%	0%
Financially hedged	13%	32%	79%
Total	93%	32%	79%
Average price of financially hedged volumes (per Mmbtu)			
Lake	$ 6.52	$ 6.90	$ 6.63
Auburndale	$ 6.68	$ 6.51	$ 6.92

In October 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando project at a weighted average price of $5.76/Mmbtu and represent approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015.

We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because both projected natural gas prices at that time and the prices in the natural gas swaps we have executed are lower than the price of natural gas being purchased under the project's gas contract.

Foreign Currency Exchange Rate Risk

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominately in Canadian dollars. Since our inception, we have had an established hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of our dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts.

The foreign exchange forward contracts are recorded at fair value based on quoted market prices and the estimation of our credit rating or the credit rating of our counterparties. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

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The following table contains the components of recorded foreign exchange (gain) loss for the three and six-month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Unrealized foreign exchange (gain) loss:				
Convertible debentures	$ 1,317	$ (6,486)	$ 6,632	$ (2,505)
Forward contracts and other	1,303	12,309	(2,133)	7,704
	2,620	5,823	4,499	5,199
Realized foreign exchange gains on forward contract settlements	(3,155)	(1,599)	(5,692)	(2,767)
	$ (535)	$ 4,224	$ (1,193)	$ 2,432

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of June 30, 2011:

Convertible debentures, at carrying value	$ 20,970
Foreign currency forward contracts	$ (20,548)

On July 27, 2011, August 3, 2011 and August 5, 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to economically hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction.

The July 27, 2011 transactions include a forward purchase of $32.0 million at $0.9460 per Cdn$1.00, a call option to purchase $84.7 million at $0.94565 per Cdn$1.00 and a put option to sell $116.7 million at $0.90 per Cdn$1.00. The August 3, 2011 transactions include a forward purchase of $76.0 million at $0.9665 per Cdn$1.00, a call option to purchase $14.5 million at $0.9665 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00. The August 5, 2011 transactions include a forward purchase of $81.2 million at $0.9872 per Cdn$1.00, a call option to purchase $9.3 million at $0.9872 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00.

Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 89% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

We have executed an interest rate swap at our consolidated Auburndale project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

We have an interest rate swap at our consolidated Cadillac project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt. The interest rate swap expires on June 30, 2025.

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements

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are not designated as hedges and changes in their fair market value are recorded in the statements of operations. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $0.7 million.

ITEM 4. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report on Form 10-Q.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) under the Exchange Act) that occurred during the period covered by this report that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations over Internal Controls

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. However, internal controls over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. 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.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Our Lake project is currently involved in a dispute with Progress Energy Florida over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by Progress. The Lake project has filed a claim against Progress in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. Progress filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of June 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

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 Part I, "Item 2-Management's Discussion and Analysis of Financial Condition and Results of Operations"), there were no material changes to the risk factors disclosed in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2010.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services LTD., CPI Investments Inc. and Atlantic Power Corporation (incorporated by reference to the Current Report on Form 8-K filed on June 24, 2011).
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.

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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 12, 2011

Atlantic Power Corporation
By: /s/ LISA J. DONAHUE

Name: Lisa J. Donahue
Title: *Interim Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*

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Schedule III

Annual Information Form of CPILP dated March 11, 2011

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Annual Information Form

For the year ended December 31, 2010

March 11, 2011

Schedule III-1

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PRESENTATION OF INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) is given at or for the year ended December 31, 2010. Amounts are expressed in Canadian dollars unless otherwise indicated. Financial information is presented in accordance with Canadian generally accepted accounting principles (GAAP).

This AIF provides material information about the business and operations of Capital Power Income L.P. (the Partnership). Any reference to the Partnership, means Capital Power Income L.P. and its subsidiaries on a consolidated basis, except where otherwise noted or the context otherwise dictates.

The "Business Risks" section of the Partnership's Management's Discussion and Analysis dated March 2, 2011 (MD&A), for the year ended December 31, 2010 is incorporated by reference into this AIF and can be found on SEDAR at www.sedar.com.

All financial information presented in millions of Canadian dollars is rounded to the nearest million unless otherwise stated.

FORWARD-LOOKING INFORMATION

Certain information in this AIF is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as "will", "anticipate", "believe", "plan", "intend", "target" and "expect" or similar words suggest future outcomes. By their nature, such statements are subject to significant risks, assumptions and uncertainties, which could cause the Partnership's actual results and experience to be materially different than the anticipated results.

In particular, forward-looking information and statements include: (i) the sustainability of distributions; (ii) planned capital expenditures at Southport in 2011 and the anticipated total cost of the North Carolina enhancement project, including capacity levels; (iii) anticipated completion of the Southport facility modifications and the impact of the Southport and Roxboro facility modifications on the operation and economic performance of the facilities and their emissions; (iv) expectations regarding the time at which the Partnership will make material cash income tax payments; (v) expectations on the throughput on the TransCanada Canadian Mainline and related expectations regarding waste heat availability at the Ontario facilities; (vi) expectations in respect of new power purchase agreements at the North Carolina facilities, including timing for their being finalized, and expectations with respect to the Partnership's long-term outlook for the North Carolina plants; (vii) expectations regarding the introduction of new emissions and other environmental regulations, when such regulations will come into force, and the costs to comply with, and other impacts of, current and anticipated emissions and other environmental regulations; (viii) the expected impact of transition to International Financial Reporting Standards; (ix) expectations of the timing of the process to review strategic alternatives and expectations that the Partnership will seek growth opportunities that fit the Partnership's strategy and deliver on business plan priorities; (x) the monthly distributions of the Partnership while the strategic review process is underway; (xi) expectations regarding the final capital cost of the Oxnard natural gas turbine replacement, and reductions in forced outage costs at Oxnard in comparison to the previous turbine; (xii) expectations regarding the quantity and duration of new wood waste supply for Calstock; (xiii) expectations regarding Ontario Power Authority as a counterparty for replacement power purchase agreements; (xiv) expectations regarding demand growth for power in Canada and the U.S., and the need for new power development; and (xv) expectations regarding the Colorado Public Utilities Commission decision in December 2010, and the filing by parties of Requests for Rehearing and Reconsideration Applications in relation thereto.

These statements are based on certain assumptions and analysis made by the Partnership in light of its experience and perception of historical trends, current conditions and expected future

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developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include, but are not limited to: (i) the Partnership's operations, financial position, available credit facilities and access to capital markets; (ii) the Partnership's assessment of commodity, currency and power markets; (iii) the markets and regulatory environment in which the Partnership's facilities operate; (iv) the state of capital markets; (v) management's analysis of applicable tax legislation; (vi) the assumption that the currently applicable and proposed tax laws will not change and will be implemented; (vii) the assumption that counterparties to fuel supply, power purchase agreements will continue to perform their obligations under the agreements taking account of the matters described herein; (viii) that current expectations regarding throughput on the TransCanada Canadian Mainline will continue; (ix) the level of plant availability and dispatch; (x) the performance of contractors and suppliers; (xi) the renewal or replacement of power purchase and other agreements including the terms and timing of power purchase agreements at the North Carolina facilities; (xii) the ability of the Partnership to successfully realize the benefits of its capital projects; (xiii) the ability of the Partnership to implement its strategic initiatives and whether such initiatives will yield the expected benefits; (xiv) expected water flows; (xv) the ability of the Partnership to adequately source alternative sources of supply of wood waste; (xvi) currently applicable and proposed environmental regulation will be implemented; (xvii) the ability to manage the transition to IFRS; and (xviii) the Partnership's assessment of the strategic alternatives that may be available to it.

Whether actual results, performance or achievements will conform to the Partnership's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results to differ materially from the Partnership's expectations. Such risks and uncertainties include, but are not limited to risks relating to (i) the operation of the Partnership's facilities; (ii) plant availability and performance; (iii) the availability and price of energy commodities including natural gas and wood waste; (iv) the performance of counterparties in meeting their obligations under fuel supply, power purchase and other agreements; (v) competitive factors in the power industry; (vi) economic conditions, including in the markets served by the Partnership's facilities; (vii) changing demand for natural gas transportation on the TransCanada Canadian Mainline; (viii) ongoing compliance by the Partnership with its current debt covenants; (ix) developments within the North American capital markets; (x) the availability and cost of permanent long term financing in respect of acquisitions and investments; (xi) unanticipated maintenance and other expenditures; (xii) the Partnership's ability to successfully realize the benefits of its capital projects; (xiii) changes in regulatory and government decisions including changes to emission regulations; (xiv) waste heat availability and water flows; (xv) changes in existing and proposed tax and other legislation in Canada and the U.S. and including changes in the Canada-U.S. tax treaty; (xvi) the tax attributes of and implications of any acquisitions; (xvii) the availability and cost of equipment; (xviii) the ability of the Partnership to adequately source alternative sources of supply of wood waste; (xix) the ability of the Partnership to obtain power purchase agreements for the North Carolina facilities with satisfactory financial terms; and (xx) the strategic review process could take more or less time than anticipated. See "Business Risks" in the Partnership's MD&A.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Forward-looking statements are provided for the purpose of presenting information about management's current expectations and plans relating to the future and readers are cautioned that such statements may not be appropriate for other purposes. Except as required by law, the Partnership disclaims any intention and assumes no obligation to update any forward-looking statement.

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DEFINITION OF CERTAIN TERMS

Certain terms used in this AIF are defined below:

"BC Hydro" means British Columbia Hydro and Power Authority

"Board" or "Board of Directors" means the board of directors of CPI Income Services Ltd., the General Partner

"Btu" means British thermal units

"Capital Power" means Capital Power Corporation together with its subsidiaries and its investment in Capital Power L.P. on a consolidated basis except where otherwise noted or the context otherwise dictates

"CHP" means combined heat and power

"CoA" means Certificate of Approval

"Common Shares" means common shares of Capital Power Corporation

"Capital Power CGCN Committee" means the Corporate Governance, Compensation & Nomination Committee of Capital Power Board of Directors

"CPEL" means CPI Preferred Equity Ltd.

"CPI Investments" means CPI Investments Inc.

"CPUC" means California Public Utility Commission

"CPUSGP" means CPI Power (US) GP

"DB" means defined benefit

"DBRS" means DBRS Limited

"DC" means defined contribution

"EBIT" means Earnings Before Interest & Taxes

"EPA" means Electricity Purchase Agreement

"EPCOR" means EPCOR Utilities Inc. collectively with its subsidiaries

"Equistar" means Equistar Chemicals, LP

"ESA" means Energy Supply Agreement

"EWG" means Exempt Wholesale Generator

"FERC" means Federal Energy Regulatory Commission

"FPA" means Fuel Purchase Agreement

"General Partner" means CPI Income Services Ltd., the general partner of the Partnership

"GWh" means gigawatt hours

"HRSG" means heat recovery steam generator

"IFRS" means International Financial Reporting Standards issued by the International Accounting Standards Board

"kWh" means kilowatt hours

"LAPP" means Local Authorities Pension Plan

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"lbs/hr" means pounds per hour

"LTIP" means long-term incentive plan

"Management and Operations Agreements" means collectively certain management and operations agreements with the Manager as described in the "Management of the Partnership" and "Interests of Management and Others in Material Transactions" sections of this AIF

"Manager" means CP Regional Power Services Limited Partnership and Capital Power Operations (USA) Inc., both subsidiaries of Capital Power

"mlbs/hr" means thousand pounds per hour

"MW" means megawatts

"MWh" means megawatt hours

"NEO" means Named Executive Officer

"NOx" means nitrogen oxide

"NUSC" means Negotiated Utility Service Contracts

"OEFC" means Ontario Electricity Financial Corporation

"Partnership" means Capital Power Income L.P. and its subsidiaries on a consolidated basis, except where otherwise noted or the context otherwise dictates

"PERC" means Primary Energy Recycling Corporation

"PERH" means Primary Energy Recycling Holdings LLC

"PPA" means Power Purchase Agreement

"PSCo" means Public Service Company of Colorado

"QF" means Qualifying Facility

"RFP" means Request for Proposal

"ROCE" means Return on Capital Employed

"S&P" means Standard & Poor's, a division of the McGraw-Hill Companies (Canada) Corporation

"SCE" means Southern California Edison Company

"SDG&E" means San Diego Gas and Electric Company

"SEDAR" means the System for Electronic Document Analysis and Retrieval, which can be accessed via the Internet at www.sedar.com

"Series 1 Shares" means the Cumulative Redeemable Preferred Shares, Series 1 issued by CPEL

"Series 2 Shares" means the Cumulative Rate Reset Preferred Shares, Series 2 issued by CPEL

"Series 3 Shares" means the Cumulative Floating Rate Preferred Shares, Series 3 issued by CPEL

"SO_2" means sulphur dioxide

"SPP" means Supplemental Pension Plan

"STIP" means short-term incentive plan

"SPA" means Steam Purchase Agreement

"SRAC" means short run avoided cost

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"The Navy" means the United States Navy

"TransCanada" means TransCanada PipeLines Limited

"TSA" means Thermal Supply Agreement

"TSX" means Toronto Stock Exchange

"Unitholders" means holders of Units

"Units" means limited partnership units of the Partnership

"U.S." means United States of America

"Ventures" means CPI USA Ventures LLC

THE PARTNERSHIP

The Partnership (formerly known as EPCOR Power L.P. and prior thereto, TransCanada Power, L.P.) was formed pursuant to a limited partnership agreement (the Partnership Agreement) dated as of March 27, 1997 and as amended and restated June 6, 1997 and as amended September 29, 1998, March 26, 2004, April 29, 2004 and August 31, 2005 and as amended and restated July 1, 2009, October 1, 2009 and November 4, 2009 among CPI Income Services Ltd. hereinafter referred to as the General Partner (formerly known as TransCanada Power Services Ltd.), the initial limited partner and each person who is admitted to the Partnership as a limited partner in accordance with the terms of the Partnership Agreement. On March 27, 1997, the Partnership was registered as a limited partnership under the laws of the Province of Ontario and was registered or extra-provincially registered, as the case may be, in all other provinces of Canada. The head office of the Partnership is located at 10065 Jasper Avenue, Edmonton, Alberta, T5J 3B1. The registered office of the Partnership is 200 University Avenue, Toronto, Ontario, M5H 3C6.

The Partnership is only permitted to carry on activities that are directly or indirectly related to the energy supply industry and to hold investments in other entities which are primarily engaged in such industry. As at December 31, 2010, the Partnership's portfolio consisted of 19 wholly-owned power generation assets located in both Canada (in the provinces of British Columbia and Ontario) and in the United States (in the states of California, Colorado, Illinois, New Jersey, New York, and North Carolina), a 50.15% interest in a power generation asset in Washington State (collectively the power plants), and a 14.3% common equity interest in Primary Energy Recycling Holdings LLC (PERH). See "General Development of the Business".

The General Partner is responsible for the management of the Partnership. The General Partner has engaged CP Regional Power Services Limited Partnership and Capital Power Operations (USA) Inc., both subsidiaries of Capital Power Corporation (Capital Power), to perform management and administrative services for the Partnership and to operate and maintain the power plants pursuant to the Management and Operations Agreements. See "Management of the Partnership" and "Interests of Management and Others in Material Transactions".

Corporate Structure

The Partnership's corporate structure is shown on Schedule A of this AIF.

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GENERAL DEVELOPMENT OF THE BUSINESS

Relationship with Capital Power

As part of the sale by EPCOR Utilities Inc. (EUI, and collectively with its subsidiaries, EPCOR) of a 27.8% interest in its power generation business to Capital Power: (i) in June 2009, CPI Investments Inc. (CPI Investments) acquired 16,511,104 limited partnership units (Units) in the capital of the Partnership and all of the common shares of the General Partner of the Partnership, which entity directly owns 2,400 Units in the capital of the Partnership, representing collectively 30.6% of the then total outstanding units of the Partnership (the Acquisition), and (ii) in July 2009, Capital Power acquired 100% ownership of the entities that provide management and operations services to the Partnership and its subsidiaries pursuant to the Management and Operations Agreements. EPCOR owns 51 voting, non-participating shares of CPI Investments and Capital Power indirectly owns 49 voting, participating shares of CPI Investments. Pursuant to the Shareholder Agreement in respect of CPI Investments, Capital Power L.P. and EPCOR agreed that: (i) the board of directors of CPI Investments shall consist of three directors; and (ii) EPCOR is entitled to nominate one person for election to the board of directors of CPI Investments.

In connection with the Acquisition, the Partnership, Capital Power and EUI entered into a Memorandum of Agreement dated June 7, 2009, pursuant to which the parties agreed on certain matters, including: (i) an approach by which Capital Power and the Partnership will work together early in the process to review Capital Power development opportunities in which the Partnership might have an interest in participating and acquisitions under the Partnership's right of first look applicable to operating power generation acquisitions (including brownfield development opportunities tied to such assets) on which Capital Power plans to bid (including through joint venture opportunities); (ii) the Partnership will have a right of first look on the sale of Capital Power generation assets so it may become the acquiring vehicle at not less than the fair market value for such assets; (iii) amendments to the incentive fee pursuant to which the Manager is compensated by the Partnership, and (iv) the basis on which the Partnership would in the future provide relief to Capital Power with respect to maintaining its minimum 30% interest in the Partnership. See "Interests of Management and Others in Material Transactions" and "Material Contracts". In addition, the Partnership and each of EPCOR and Capital Power entered into standstill agreements pursuant to which Capital Power and EPCOR agreed not to increase their ownership in the Partnership without the consent of the Independent Directors of the Partnership until July 1, 2010.

As a result of the Premium Distribution™ and Distribution Reinvestment Plan (the DRIP), as of December 31, 2010, CPI Investments, through its direct ownership of Units and 100% ownership of the General Partner, indirectly owned 29.6% of the outstanding Units.

™ Denotes a trademark of Canaccord Capital Corporation

As at December 31, 2010, the Partnership's assets, excluding its interests in PERH, had a total net generating capacity of 1,400 MW and more than four million pounds per hour of thermal energy.

Amendments to Limited Partnership Agreement

In connection with the sale by EPCOR of its power generation business to Capital Power, effective July 1, 2009, the Limited Partnership Agreement governing the Partnership was amended and restated to reflect the acquisition by Capital Power from EPCOR of the ownership interests in the Partnership. In connection with the launch of the DRIP, effective October 1, 2009 the Limited Partnership Agreement was amended and restated to provide for distributions to limited partners on a monthly basis, and, as contemplated in the Memorandum of Agreement dated June 7, 2009, to provide relief to Capital Power with respect to maintaining its minimum 30% interest in the Partnership. See

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"Distributions of the Partnership". Effective November 4, 2009, the Limited Partnership Agreement was amended and restated to change the name of the Partnership to Capital Power Income L.P.

Three Year History

The general development of the Partnership's business during the last three financial years, and the significant acquisitions and events or conditions which have had an influence on such development, are described below.

2010

In November 2010, the Partnership completed the final phase of the enhancement project on the North Carolina facilities designed to reduce environmental emissions and improve economic performance by increasing the use of tire-derived fuel and wood waste in the fuel mix and significantly reducing the nitrogen oxide (NOx) and sulphur dioxide (SO_2) emissions. Project costs incurred to December 31, 2010, including costs incurred prior to 2010, were US$82 million with an additional US$5 million to be spent in 2011 on access roads and final testing.

On October 5, 2010, the Partnership and Capital Power announced that the Partnership had initiated a process to review its strategic alternatives. This decision was the result of separate strategic review processes undertaken by the Special Committee of the independent directors of the Board to maximize value for the Partnership's Unitholders and by Capital Power to maximize value for Capital Power's shareholders. The initiation of the strategic review was not in response to any proposed transaction for the Partnership and there is no assurance that it will lead to a transaction. During the process to review strategic alternatives it is anticipated that the Partnership will continue to provide the same amount of monthly distributions to its Unitholders, maintain the same investor proposition supported by its high quality portfolio of contracted power assets and deliver on business plan priorities.

In July 2010, the Partnership filed a renewal of its Short Form Base Shelf Prospectus in each of the provinces and territories of Canada qualifying the issuance by the Partnership from time to time over a period of 25 months of up to $600 million in securities consisting of Units, debt securities and/or subscription receipts.

In May 2010, the Partnership completed the replacement of the existing GE LM5000 natural gas turbine with a more efficient and reliable GE LM6000 at Oxnard at a cost of US$19.2 million. The final capital cost could potentially be lower if the sale of the used General Electric LM5000 turbine is successful. The repowering project was completed on May 21, 2010, in time for the summer peak demand season in Southern California.

2009:

To December 31, 2009, the Partnership incurred a total of US$70.7 million on the enhancement project designed to reduce environmental emissions and improve the economic performance of the Southport and Roxboro facilities. Enhancements to the Roxboro facility and to one of the two units at the Southport facility were completed in December 2009.

On November 2, 2009, CPI Preferred Equity Ltd. (CPEL), a subsidiary of the Partnership, issued 4,000,000 Cumulative Rate Reset Preferred Shares, Series 2 (Series 2 Shares) for gross proceeds of $100 million. The net proceeds were used to repay outstanding bank indebtedness. The Series 2 Shares are fully and unconditionally guaranteed by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of CPEL. If, and for so long as, the declaration or payment of dividends on the Series 2 Shares is in arrears, the

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Partnership will not make any distributions on the Units. See "Dividends of Subsidiary (CPEL)" and "Capital Structure Preferred Shares of CPEL" in this AIF and "Business Risks Preferred Share guarantee unit distribution risk" in the Partnership's MD&A.

In August 2009, the Partnership converted all of its common and preferred interests in PERH to a 14.3% common equity interest in connection with a recapitalization of PERH, pursuant to which all previously outstanding common and preferred interests in PERH, including those held by the Partnership, were converted to new common equity interests. Primary Energy Recycling Corporation (PERC) completed its previously announced US$50 million rights offering in November 2009 and, concurrently with PERC's subscription for new common membership interests in PERH, the Partnership exercised its pre-emptive right to subscribe for additional common membership interests to maintain its current pro-rata interest (14.3%) in PERH at an aggregate subscription price of US$8.3 million. Concurrently with the PERH recapitalization, certain changes were made to the long-term management agreement pursuant to which a subsidiary of the Partnership provides certain management and administrative services to PERH, certain subsidiaries of PERH and PERC (PERC Management Agreement). See "Business of the Partnership PERC Management Arrangements" and "Material Contracts".

On May 26, 2009, the Partnership completed the sale of its 64 MW combined-cycle, natural gas and oil-fired Castleton power plant for approximately US$10.7 million.

On May 1, 2009, the Partnership completed the repowering project for its North Island facility, which involved the replacement of its GE LM5000 natural gas turbine with a more efficient GE LM6000 unit at a cost of approximately US$17.0 million.

2008:

On October 31, 2008, the Partnership, through an indirect wholly-owned subsidiary, acquired a 100% interest in Morris Cogeneration, LLC, which owns a 177 MW natural gas-fired cogeneration facility for total cash consideration of US$73.4 million.

In July 2008, the Partnership filed a Short Form Base Shelf Prospectus in each of the provinces and territories of Canada qualifying the issuance by the Partnership from time to time over a period of 25 months of up to $1 billion in securities consisting of Units, debt securities and/or subscription receipts. Concurrent with the prospectus filing, a Prospectus Supplement was filed, establishing a Medium Term Notes program of up to $600 million as part of the overall prospectus limit.

BUSINESS OF THE PARTNERSHIP

The Partnership's primary business is the ownership and operation of power plants in Canada and the United States, which generate electricity and steam, from which it derives its earnings and cash flows. The power plants generate electricity and steam from a combination of natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel.

Power Plant Summary

The Partnership's Canadian operations consist of:

- four natural gas-fired plants with a combined generating capacity of 163 MW;
- two biomass, wood waste plants with a combined generating capacity of 101 MW; and
- two hydroelectric facilities with a combined generating capacity of 56 MW.

The Partnership's United States operations consist of:

two natural gas-fired plants with a combined generating capacity of 425 MW;

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seven natural gas-fired CHP plants, three of which can also use distillate fuel, with a combined generating capacity of 440 MW and steam generating capacity of 2,537 mlbs/hr;

two wood waste, tire-derived fuel and coal CHP plants with a maximum combined generating capacity of 155 MW and steam generating capacity of 1,620 mlbs/hr; and

a hydroelectric plant with a total generating capacity of 60 MW.

The following two pages summarize each of the Partnership's 20 power plants and their operating characteristics.

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	Nipigon	Kapuskasing	North Bay	Tunis	Calstock	Williams Lake	Mamquam	Moresby Lake	Frederickson	Manchief
Electric Capacity(1)	40 MW	40 MW	40 MW	43 MW	35 MW	66 MW	50 MW	6 MW	125 MW + 10 MW duct firing(5)	301 MW
Location	Nipigon, Ontario	Kapuskasing, Ontario	North Bay, Ontario	Iroquois Falls, Ontario	Hearst, Ontario	Williams Lake, British Columbia	Mamquam River, British Columbia	Moresby Island, British Columbia	Pierce County, Washington	Brush, Colorado
Type	Enhanced combined cycle gas-fired generation	Enhanced combined cycle gas-fired generation	Enhanced combined cycle gas-fired generation	Enhanced combined cycle gas-fired generation	Enhanced biomass wood waste generation	Biomass wood waste generation	Hydroelectric run-of-river	Hydroelectric reservoir-based station	Combined cycle gas-fired generation	Simple-cycle gas-fired generation
Major Equipment	22 MW gas turbine, 18 MW steam turbine, 3 HRSGs	25 MW gas turbine, 20 MW steam turbine, 3 HRSGs	25 MW gas turbine, 20 MW steam turbine, 2 HRSGs	31 MW gas turbine, 17 MW steam turbine, 4 HRSGs	Wood waste boiler, 41 MW steam turbine, 2 HRSGs	Wood waste boiler, 66 MW steam turbine	2 hydroelectric turbines	3 hydroelectric turbines	166 MW combustion turbine, 88 MW steam turbine	2 gas turbines
Commercial Operations	1992	1997	1997	1995	2000	1993	1996	1990	2002	2000
PPA Expiry	2012(2)	2017	2017	2014	2020	2018 with an option for 2 extensions of 5 years each	2027(4) with an option to extend and purchase facility at the end of the term	2022	2022	2022(7)
Counterparty to PPAs	OEFC	OEFC	OEFC	OEFC	OEFC	BCH	BCH	BCH	3 Public Utility Districts (PUDs)(6)	PSCo
FPA Expiry	Gas supply agreements expiring 2012	Gas supply agreement expiring 2017	Gas supply agreement expiring 2017	Month to month	Wood waste agreements with three local mills expiring 2019	5 wood waste agreements expiring 2018. 1 wood waste agreement expiring 2014(3)			PUDs are responsible for fuel supply	PSCo is responsible for the fuel supply
Fuel Supply	NAL, Petrobank	TCPM	TCPM		Tembec, Lecours, Columbia					

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The legal names of the respective counterparties are:
British Columbia Hydro and Power Authority (BCH)
Columbia Forest Products, Inc. (Columbia)
Devon Canada Corporation (Devon)
Lecours Lumber Co. Limited (Lecours)
NAL Resources Ltd. (NAL)
Ontario Electricity Financial Corporation (OEFC)
Petrobank Energy and Resources Ltd. (Petrobank)
Public Service Company of Colorado (PSCo)
Tembec Inc. (Tembec)
TransCanada Power Marketing Ltd. (TCPM)

Notes:

(1) Electric capacity is shown as net generation.

(2) The Partnership has the option to extend the PPA for 10 years at existing terms.

(3) Several periodic suppliers continue to supply on an as available and needed basis. Several long-term suppliers have temporarily curtailed operations but the new 5-year agreement with Pioneer Biomass Inc. more than offsets the expected shortfall. See "Business Risks" in the MD&A

(4) BCH has an option exercisable in 2021 and every five years thereafter to buy the Mamquam facility or extend the contract.

(5) Represents Partnership's 50.15% ownership interest in Frederickson. Puget Sound Energy, Inc. owns the remaining 49.85% ownership interest.

(6) Public Utility Districts are: Benton, Franklin and Grays Harbor.

(7) PSCo has an option during the latter part of the extension term to purchase the Manchief facility.

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	Greeley	Naval Station	North Island	Naval Training Center	Oxnard	Curtis Palmer	Morris	Kenilworth	Roxboro	Southport
Electric Capacity(1)	72 MW	47 MW	40 MW	25 MW	48 MW	60 MW	177 MW	30 MW	52 MW(5)	103MW(5)
Steam Capacity	170 mlbs/hr	479 mlbs/hr	390 mlbs/hr	220 mlbs/hr	120 mlbs/hr		1,080 mlbs/hr	78 mlbs/hr	540 mlbs/hr	1,080 mlbs/hr
Location	Greeley, Colorado	San Diego, California	San Diego, California	San Diego, California	Oxnard, California	Hudson River near Corinth, New York	Morris, Illinois	Kenilworth, New Jersey	Roxboro, North Carolina	Southport, North Carolina
Type	Natural gas-fired CHP facility	Dual-fuel (natural gas or No. 2 distillate fuel oil) CHP facility	Natural gas-fired CHP facility	Dual-fuel (natural gas or No. 2 distillate fuel oil) CHP facility	Natural gas-fired CHP facility	Hydroelectric impoundment and run-of-river	Natural gas-fired CHP facility	Dual fuel (natural gas or No. 2 distillate fuel oil) CHP facility	Coal, tire-derived fuel and wood waste CHP facility	Coal, tire-derived fuel and wood waste CHP facility
Major Equipment	Two 35 MW gas turbines, 12 MW steam turbine, 2 HRSGs	37 MW gas turbine, 10 MW steam turbine, 1 HRSG	36 MW gas turbine, 4 MW steam turbine, 1 HRSG	22 MW gas turbine, 2.5 MW steam turbine, 1 HRSG	49 MW gas turbine, 1 HRSG, 1 AAARP	7 turbines	3 combustion turbine-generators, 3 HRSGs, 60 MW steam turbine generator	23 MW gas turbine, 7 MW steam turbine, 1 HRSG	3 stoker boilers, 57.4 MW steam turbine	6 stoker boilers, two 57.4 MW steam turbines
Commercial Operations	1988	1989	1989	1989	1990	1986(2)	1998	1989	2009(6)	2010(6)
PPA Expiry	2013	2019	2019	2019	2020	2027 or delivery of 10,000 GWh	2023 (77 MW) 2011 (100 MW)	2012	Under negotiation	Under negotiation
Counterparty to PPAs	PSCo	SDG&E	SDG&E	SDG&E	SCE	Niagara	ECLP, EGC LLC	Schering	CP&L	CP&L
SPA Expiry	2013	2018	2018	2018			2023	2012(3)		2014
Counterparty to SPAs	UNC	U.S. Navy	U.S. Navy	U.S. Navy	Boskovich		ECLP	Schering		ADM
FPA Expiry	Gas supply agreement expiring in 2011	Gas supply agreement expiring 2011	Gas supply agreement expiring 2011	Gas supply agreement expiring 2011	Gas supply agreement expiring 2011		Gas supply agreement expiring 2016	Month-to-month gas supply	Annual(7)	Annual(7)
Fuel Supply	SENA	SETC	SETC	SETC	SETC		TPSC	SETC(4)		

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The legal names of the respective counterparties are:
Archer Daniels Midland Company (ADM)
Boskovich Farms, Inc. (Boskovich)
Carolina Power & Light Company (CP&L)
Equistar Chemicals, LP (ECLP)
Exelon Generation Company LLC (EGC LLC)
Niagara Mohawk Power Corporation (Niagara)
Public Service Company of Colorado (PSCo)
Public Service Enterprise Group (PSE&G)
San Diego Gas & Electric Company (SDG&E)
Schering-Plough Corporation (Schering)
Sempra Energy Trading Corporation (SETC)
Shell Energy North America (US), L.P. (SENA)
Southern California Edison Company (SCE)
Tenaska Power Services Co. (TPSC)
University of Northern Colorado (UNC)

Notes:

(1) Electric capacity is shown as net generation.

(2) The Curtis Palmer facility was repowered in 1986.

(3) Steam is sold to Schering under the PPA.

(4) Gas is purchased from a local gas distribution company and Sempra Energy Trading Corporation.

(5) Maximum capacity utilizing 100% coal for fuel supply.

(6) Enhancements to the Roxboro facility and to one of the two units at Southport facility were completed in December 2009. Enhancements to the second unit were completed in November 2010. The Roxboro and Southport facilities originally commenced operations in 1987.

(7) Approximately 25-30% of the Southport and 20-24% of the Roxboro facilities' fuel requirements are satisfied with coal, with the balance from tire-derived fuel and wood waste. The anticipated coal requirements for each facility are sourced with regional coal suppliers.

AAARP = Anhydrous ammonia absorption refrigeration plant
HRSG = Heat recovery steam generator
CHP = Combined Heat and Power

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Power Purchase Agreements

Canada

Ontario

The Ontario Electricity Financial Corporation (OEFC) is the sole purchaser of power from the Partnership's five Ontario power plants. The power is purchased under long-term Power Purchase Agreements (PPAs). The earliest expiry date of these agreements is at the Nipigon plant where the initial term of the PPA expires in 2012 and the longest expiry date is at the Calstock plant where the PPA expires in 2020. See "Power Plant Summary". The Partnership reached an agreement with the OEFC to amend the Tunis PPA effective January 16, 2010 that allows the Partnership to flow-through natural gas and transportation costs in excess of benchmark amounts to OEFC and extends OEFC the right to curtail the plant during summer off-peak periods through the remaining term of the PPA in 2014.

Williams Lake

The Williams Lake power plant sells power to the British Columbia Hydro and Power Authority (BC Hydro) under a 25-year PPA with the initial term expiring in 2018. BC Hydro has an option to extend the agreement by up to 10 years, on the basis of two five-year term extensions.

The Williams Lake Electricity Purchase Agreement (EPA) contains two pricing tranches: a firm energy tranche, representing approximately 82% of total energy produced; and a surplus energy tranche, representing approximately 18% of total energy produced. The firm energy tranche price consists of a fixed energy component, an operations and maintenance component (adjusted annually for average weekly earnings in British Columbia), and a reimbursable cost component. The surplus energy tranche price is adjusted annually for changes in the Dow Jones California Oregon Border index. The year end surplus energy tranche price would have been set at $30/MWh for 2010, compared to $58/MWh for 2009. However the Partnership sold the surplus energy to a third party at a higher price. The surplus energy price for 2011 was set through negotiations with BC Hydro and is attractive.

Mamquam

The Mamquam hydroelectric facility sells all of its electricity generated to BC Hydro under a long-term contract (Mamquam EPA) which will expire in October 2027. BC Hydro has an option, exercisable in 2021 and every five years thereafter, to either purchase the Mamquam facility or extend the Mamquam EPA.

Energy rates payable under the Mamquam EPA consist of a fixed energy component, an operations and maintenance component (adjusted annually for inflation), and a reimbursable cost component which covers costs such as property taxes, water and land use fees as well as comprehensive liability insurance costs.

Moresby Lake

The Moresby Lake hydroelectric facility sells substantially all its electricity to BC Hydro under a long-term contract (Moresby Lake PPA) which will expire in 2022. The balance, approximately 1% of its power generation, is sold to NAV Canada and the Department of Fisheries and Oceans (Canada) under long-term PPAs.

The energy rate payable by BC Hydro under the Moresby Lake PPA consists of a fixed energy component adjusted annually for inflation.

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United States

Frederickson

The Partnership's portion (50.15% or approximately 125 MW) of the Frederickson facility's base 249 MW generating capacity has been sold under PPAs to three Washington State Public Utility Districts (PUDs) for a term of 20 years ending in 2022. Under the PPAs, the Partnership provides generating capacity and associated energy to each PUD, and the PUDs pay the Partnership a capacity charge, a fixed operations and maintenance charge, a variable operations and maintenance charge and a fuel charge. The PUDs must supply their proportionate share of natural gas to the Partnership at Huntingdon, British Columbia. The Partnership is responsible for contracting firm transportation for natural gas from Huntingdon to the Frederickson facility. The Partnership is responsible for any fixed and variable cost increases above those recoverable under the PPAs, other than costs that result from the effects of material changes to environmental and tax laws.

Manchief

The Manchief power plant operates under an Energy Supply Arrangement (ESA) with the Public Service Company of Colorado (PSCo) that expires in 2022 pursuant to a 10-year extension agreed to in 2006. PSCo is an electricity and natural gas distribution company that primarily serves northern Colorado. Under the ESA, PSCo purchases: (i) the electricity capacity consisting of 301.8 MW of net generating capacity per hour, or the actual net generating capacity that is available in any given hour, whichever is less; and (ii) the electrical energy which is actually dispatched by PSCo and associated with such capacity, and Manchief is paid capacity and energy payments. Capacity payments are typically stable and are made on a monthly basis, regardless of whether the plant is actually dispatched by PSCo. Energy payments are also made on a monthly basis and are comprised of tolling fees, start-up fees, heat rate adjustment payments (payable either to or by Manchief) and natural gas transportation charges. Starting in May 2012, the capacity payments will be reduced by approximately 15% under the tolling arrangement.

Manchief obtains operations and maintenance services for its generating facility from Colorado Energy Management, LLC pursuant to the terms of a plant operating and maintenance agreement.

The Partnership and PSCo have also signed an Option Agreement under which PSCo has the right, during the latter part of the ESA extension term, to acquire the Manchief power plant. If PSCo exercises the purchase option, the Partnership would receive a fixed purchase price, as specified in the Option Agreement, which management believes will maintain the economic value of the 10-year ESA extension and compensate the Partnership for the power plant's expected residual value.

Greeley

The Greeley facility provides all of its electrical output to PSCo under an on-system PPA which expires in August 2013. PSCo pays the Greeley facility a monthly capacity payment and energy payment pursuant to the PPA. The Partnership entered into a three-year forward natural gas swap contract expiring in October 2011 that covers most of the anticipated supply requirements for the Greeley facility during this period. Extension of the forward swap to cover the expiry of the PPA is being evaluated by management.

Under a development agreement between Ventures and KN/Thermo LLC, KN/Thermo LLC is currently entitled to up to 33.5% of the Pre-Tax Cash Flow from the Greeley facility. Pre-Tax Cash Flow is defined in the development agreement to include the net proceeds realized by the Partnership from the sale of the Greeley facility under certain circumstances, and cash proceeds received from operation of the Greeley facility (including from sales of electric power and hot water), as reduced by the reasonable operating costs of the facility.

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California Facilities

The Partnership's California facilities are comprised of three facilities located on U.S. naval bases (the Naval Facilities) and the Oxnard facility.

The Naval facilities are comprised of Naval Station, North Island and Naval Training Center. Except for the 4 MW steam turbine at the North Island facility, each of the Naval Facilities provides all of its electrical output to San Diego Gas and Electric Company (SDG&E) under the terms of the Long Run Standard Offer No. 4 for Power Purchase and Interconnection agreements from Qualifying Facilities, each of which expire in 2019. SDG&E is an electricity and natural gas distribution company primarily serving the San Diego area. Each of the Naval Facilities is required to operate throughout the term of the applicable PPA as a Qualifying Facility (QF) in accordance with the cogeneration facility requirements established by the Federal Energy Regulatory Commission (FERC).

In 2009, the Partnership completed an upgrade to its gas turbine at the North Island facility in southern California from a GE LM5000 to a GE LM6000 unit for an approximate cost of US$17.0 million. The repowering project was completed in time for the summer peak demand season in Southern California. The project improved the operating efficiency of the facility reducing the gas turbine gross heat rate by approximately 1,127 Btu/kWh. The replaced LM5000 unit will be available as a spare gas turbine for the Partnership's other LM5000 turbines. The energy produced by the 4 MW steam turbine at the North Island facility is sold to the U.S. Navy (the Navy) at a discount to SDG&E's retail rates. The energy produced by the 2.5 MW steam turbine at the Naval Training Center is sold to SDG&E under a Standard Offer No. 1 for Power Purchase and Interconnection from Qualifying Facilities (SO1). The energy rates under the SO1 are the SDG&E short run avoided cost (SRAC) rates. Capacity payments are paid on an as-available basis under rates that are reviewed by the California Public Utility Commission (CPUC) periodically.

The Navy has the right to terminate the Naval Facility Negotiated Utility Service Contracts (NUSCs) for convenience on one year's notice. Termination costs incurred under the PPA would be reimbursed under the NUSC in the event of termination for convenience. See "Thermal Supply Agreements".

The Oxnard facility provides all of its natural gas turbine electrical output to Southern California Edison Company (SCE) under a contract (Oxnard PPA) that expires in 2020. SCE is an electricity and natural gas distribution company primarily serving areas of southern California outside Los Angeles and San Diego. The Oxnard facility is required to operate throughout the term of the Oxnard PPA meeting QF efficiency standards in accordance with the cogeneration facility requirements established by the FERC. The Oxnard facility is qualified as both a QF and an Exempt Wholesale Generator (EWG).

In May 2010, the Partnership completed the replacement of the existing GE LM5000 natural gas turbine with a more efficient and reliable GE LM6000 at Oxnard at a cost of US$19.2 million. The final capital cost could potentially be lower if the sale of the used General Electric LM5000 turbine is successful. The repowering project was completed in time for the summer peak demand season in Southern California. While the project improved the Oxnard facility heat rate by 3%, the primary economic driver of the project is an expected reduction in forced outage costs relative to the GE LM5000.

The price paid under the Naval Facilities' PPAs includes a capacity payment and an energy payment based on SDG&E's SRAC. The price paid under the Oxnard PPA includes a capacity payment and an energy payment based on SCE's SRAC. Capacity payments are based on achieving availability performance targets. These performance requirements require that forced outage rates for the facility are to be less than 20% during specified on-peak hours during the summer peak demand months. An additional performance bonus is applied when on-peak forced outage rates are less than 15%. Each of the Naval Facilities and the Oxnard facility has historically achieved its firm capacity revenue and near maximization of capacity bonus revenues.

On September 20, 2007, the CPUC accepted an alternative decision regarding revisions to the SRAC formulae that became effective August 1, 2009. The essence of the decision was to provide a 50/50 split between market and administratively determined heat rates for the calculation of the overall heat rate used in the energy price calculation; provide an escalating operating and maintenance fee adder; and use a 12-month forward-looking market heat rate rather than the historical pricing. The SRAC change impacts the steam payment component of the Naval Facilities PPAs and the Partnership is currently in discussions with the Navy regarding implications of future steam pricing. See "Regulation California".

SRAC energy prices are published monthly in accordance with the above mentioned decision. As such, this pricing provision recovers the month-to-month natural gas costs related to electricity production and substantially passes through the fuel cost to SDG&E and SCE in the variable energy charge. Time of use factors are applied to the SRAC energy rate to value the electricity delivered during on-peak hours relative to electricity delivered during off-peak hours. The Oxnard facility typically operates during on-peak hours in order to take advantage of higher electricity prices provided from on-peak time of use rates. Changes in natural gas prices have a nominal impact on the Oxnard facility's operating margin.

Curtis Palmer

The Curtis Palmer hydroelectric facility sells all power generated to Niagara Mohawk Power Corporation (Niagara) under a long-term contract (Curtis Palmer PPA). The Curtis Palmer PPA ends after the earlier of 2027 and the delivery to Niagara of a cumulative 10,000 GWh of electricity.

The Curtis Palmer PPA sets out 11 different prices for electricity sold to Niagara, with the applicable price to be paid at any given time being dependent upon the cumulative GWh of electricity which have been delivered to Niagara. In December 2008, the pricing increased by 18% as the plant moved into the sixth pricing block. Over the remaining term of the PPA, the price increases by US$10/MWh with each additional 1,000 GWh of electricity delivered. The plant requires approximately three years to move through each 1,000 GWh block, depending upon river flow.

Under certain circumstances, Niagara has the ability to relocate, rearrange, retire or abandon its transmission system which would potentially give rise to material future capital cost outlays by Curtis Palmer to maintain its interconnection.

Morris

The Morris facility sells electrical energy to Equistar Chemicals, LP (Equistar), a wholly-owned subsidiary of LyondellBasell AF S.C.A. (LyondellBasell), under an ESA that expires in 2023. Pursuant to the Morris ESA, Equistar pays a tiered energy rate based on the amount of energy consumed to a maximum of 77 MW. Equistar also pays capacity fees, comprised of both a non-escalating fixed fee that expires in 2013 and a variable fee that escalates with materials and labour indices and expires in 2023. The non-escalating capacity payment is fixed at US$8.3 million per year. In addition, the Morris facility earns energy payments based on electricity and steam delivered that is adjusted monthly for natural gas prices. Based on the energy payment formula, there is a small portion of energy costs that are not recovered through the energy payments, and this non-recoverable amount fluctuates with the price of natural gas. Most of this natural gas price exposure has been hedged through 2011. Equistar has a right to purchase the Morris facility at fair market value at the end of 2013, 2018 and 2023. The Morris facility is certified as a QF.

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Subordinate to the needs of Equistar, the Morris facility has a PPA with Exelon Generation Company, LLC (Exelon) covering 100 MW of electrical capacity that expires in April 2011. Exelon pays a capacity charge that varies based on the time of year together with an energy charge based on amount of energy dispatched. The annual capacity revenue earned under the PPA with Exelon has averaged just over US$6 million per year, including bonus payments for peak availability that exceeds 98%.

Excess capacity and energy above the needs of Equistar and Exelon can be sold into the Pennsylvania, New Jersey, and Maryland (PJM) market. The 100 MW of electrical capacity that is currently serving the Exelon PPA has been sold through the PJM market from May 2011 to April 2014 at auction prices that are lower than the Exelon contract resulting in slightly lower capacity revenue.

On January 6, 2009, Equistar, along with LyondellBasell's other North American operating entities, filed a voluntary petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Since that date, Equistar made all post-petition payments required under the ESA. On April 23, 2010 the plan of reorganization for LyondellBasell's U.S. subsidiaries, including Equistar, under Chapter 11 of the U.S. Bankruptcy Code was approved. Pursuant to the plan of reorganization, Equistar assumed the Morris ESA, and as a result, the Partnership received a US$12.4 million payment for pre-petition services under the ESA along with interest.

Kenilworth

The Kenilworth facility sells electrical energy to Schering-Plough Corporation (Schering), a subsidiary of Merck & Co., Inc., under an amended and extended ESA that expires in July 2012. Pursuant to the Kenilworth ESA, Schering pays an energy rate that escalates annually. The Kenilworth ESA imposes a minimum take or pay obligation on Schering of 125,000 MWh per year. Load growth at Schering's facility over the years has caused certain seasonal loads to match more closely with the capacity of the Kenilworth facility. Excess generation above the Schering loads are sold to Public Service Enterprise Group Incorporated under a contract entered into in 2009.

North Carolina Facilities

The Roxboro and Southport facilities provide all of their electrical output under PPAs to Carolina Power & Light Company (CP&L), which is a regulated utility servicing North Carolina and South Carolina, and is a subsidiary of Progress Energy Inc. (Progress). The electric output from the facilities is sold to Progress pursuant to PPAs which expired on December 31, 2009, but which have been extended pending resolution of arbitration before the North Carolina Utilities Commission (NCUC). The Partnership filed for arbitration with the NCUC and is seeking long term PPAs with pricing terms consistent with Progress's actual avoided costs. The NCUC has ordered that Progress continue to pay for the output of the North Carolina facilities pursuant to the terms of the PPAs that expired December 31, 2009 until the arbitration is finalized. On this interim basis, the price paid includes a capacity payment, an energy payment that reflects the price paid for coal, and a cycling charge. If this pricing does not result in a dispatch order for the facility, the Partnership has the right, but not the obligation, to bid an alternate price based upon its own pricing strategies to obtain a dispatch order. See "Business Risks Power Purchase Contract Expiry Risk" in the MD&A. On January 27, 2011, the NCUC issued an Order on Arbitration which provided direction on four fundamental issues: (i) that a legally enforceable obligation was created in July 2008 and that, accordingly, it is appropriate to use Progress' June 2008 fuel forecasts as the basis for determining the avoided cost fixed energy rates for the new PPAs; (ii) that the facilities are entitled to receive full capacity payments in respect of the full term of the PPAs; (iii) that Progress' avoided capacity costs should be calculated based on the average unit cost to construct four combustion turbines at a single site; and (iv) that a 10-year term would be fair and appropriate for the new PPAs with the term starting from the time when the new PPAs are signed. The Order on Arbitration did not set a deadline for the completion of negotiations but requires

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the Partnership and Progress to report on the status of negotiations within 30 days, if no agreement is reached sooner. On February 25, 2011, a joint report on the status of negotiations was filed in which the parties state that they have reached agreement on the majority of key commercial terms and will begin drafting final PPAs, with the goal of having an April 1, 2011 effective date.

The North Carolina facilities burn a mix of wood waste, tire-derived fuel and coal. Both facilities have undergone substantial capital improvements designed to significantly reduce their NOx and SO_2 emissions. These changes will additionally reduce the facilities' fuel costs via increased use of wood waste and tire-derived fuel accommodated via modified equipment design. In the fourth quarter of 2010, the Partnership completed the final phase of the enhancement project designed to reduce environmental emissions and improve the economic performance of the Southport and Roxboro facilities by increasing the use of tire-derived fuel and wood waste in the fuel mix. Project costs incurred to December 31, 2010 were US$82 million with an additional US$5 million to be spent in 2011 on access roads and final testing. The Partnership had anticipated a reduction in the capacity of Southport and Roxboro to approximately 88 megawatts (MW) and 46 MW respectively as a result of the increased use of wood waste and tire-derived fuel. The reduction in the capacity levels as a result of the change to a greater level of wood waste and tire-derived fuel in the fuel mix may be greater than previously expected. Recent testing indicates the plants may only be able to achieve capacities of 84-87 MW at Southport and 42-44 MW at Roxboro based on the targeted fuel mix. Management is assessing whether a shortfall in capacity can be practically resolved.

As QFs under the FERC rules, both Roxboro and Southport can sell to CP&L under a special avoided cost rate determined every two years, and can supplement this revenue stream with sales of Renewable Energy Credits (REC) to satisfy North Carolina's Renewable Energy Portfolio Standard. As part of the capital investment, both plants dramatically increased their wood fuel percentage and thus achieved certification as REC providers. To reclaim its QF status, Roxboro increased its minimum non-coal fuel percentage to 75%, thus qualifying as a Small Power Producer on January 1, 2010. The Southport facility has been QF certified since initial operations in 1987.

Thermal Supply Agreements

The Greeley facility sells hot water to the University of Northern Colorado (UNC) pursuant to a Thermal Supply Agreement (TSA) which expires in August 2013. Under the Greeley TSA, the Greeley facility is obligated to deliver for sale to UNC only such heat energy as is generated during the production of electrical capacity and energy for sale to PSCo. The charge per million Btu of thermal energy is calculated in a manner that gives UNC a discount when compared to UNC avoided natural gas-fired boiler costs.

The Naval Facilities sell steam to the Navy pursuant to NUSCs, each of which expires in February 2018. The Naval Facility NUSCs give the Navy a right to purchase electrical energy from the Naval Facilities at prices comparable to those under the Naval Facility PPAs. Under the Naval Facility NUSCs, the Navy has an obligation to consume enough thermal energy for the Naval Facilities to maintain their QF status. The Navy has the right to terminate the SPAs for convenience on one year's notice. The Navy is obligated to pay a termination payment if it breaches an agreement or causes any loss of a Naval Facility's QF status.

The contracted steam for the Naval Facilities is based on a take or pay formula using a specified volume at each facility. Additional steam can be taken above these specified volumes and such steam is priced at avoided package boiler costs. The monthly price payable by the Navy for steam under the Naval Facility NUSCs includes: (i) a steam commodity charge; (ii) fixed service charge for plant capital and operations and maintenance avoidance; and (iii) water cost pass-through provisions, a feed water charge and a credit for condensate return.

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Steam pricing is linked to the cost of natural gas and SDG&E's SRAC by an energy sharing formula. This formula provides the Naval Facilities with reduced price volatility as the SRAC price of electricity primarily increases or decreases as a result of changes to the price of natural gas. Changes in natural gas prices have a nominal impact on the Naval Facilities' cash provided by operating activities. On September 20, 2007, the CPUC accepted an alternative decision regarding revisions to the SRAC formulae that became effective on August 1, 2009. See "Regulation California".

The Oxnard facility supplies steam to its anhydrous ammonia absorption refrigeration plant, which then provides refrigeration services to Boskovich Farms at no charge; thereby maintaining the Oxnard facility's QF status.

The Morris facility sells steam to Equistar to a maximum of 720 million lbs/hr under the Morris ESA through 2023. Ten year average usage is approximately 320 million lbs/hr. The Morris ESA charge for steam is calculated on the basis of a tiered pricing schedule ranging from US$2.60/mlbs of steam to US$3.18/mlbs of steam depending on quantity of average monthly steam demand. The agreement provides for the option to renegotiate pricing if steam demand falls outside a set range for a stipulated period of time. See "Power Purchase Agreements United States Morris" in this AIF, and "Business Risks Qualifying Facility Status Risk" in the MD&A.

The Kenilworth facility sells steam to Schering under an amended and extended Kenilworth ESA that expires in July 2012. The Kenilworth ESA provides for a contract minimum of 160,000 million Btu per year. The average annual heat content of steam sales directly from the Kenilworth facility under the terms of the Kenilworth ESA has been higher (740,000 million Btu per year average) than the contract minimum. The Kenilworth ESA charge per million Btu of steam is calculated as a function of the delivered cost of fuel to Schering's auxiliary boilers. Schering is able to request long term purchase strategies to minimize the monthly volatility of natural gas prices.

The Partnership filed for market-based rate authority with the FERC, which was granted effective January 1, 2008, in endeavoring to ensure that the Roxboro facility would have the requisite authority in place to sell power under the Roxboro PPA in the event the facility does not have a steam host. Currently, the facility does not have a steam host and the Partnership does not expect one to emerge. The Southport facility sells steam pursuant to a Steam Purchase Contract which expires in December 2014 to Archer Daniels Midland Company (ADM). ADM has committed to purchase a minimum quantity of steam equivalent to 5% of the total energy output of the Southport facility. The Southport facility is required to make all reasonable efforts to provide a continuous supply of steam. However, the Southport facility is not responsible for any loss or damage resulting from a failure to maintain continuous steam service. Southport operates the boilers to provide steam continuously, even when the plant is not dispatched.

Fuel Purchase Agreements

The largest of the Partnership's expenses is the cost of fuel used in the generation of electricity. Fuel costs include the natural gas commodity price, natural gas transportation charges, waste heat optimization costs and wood waste costs at the Calstock and Williams Lake plants and wood waste, tire-derived and coal fuel prices and transportation costs at the Roxboro and Southport facilities. Wood waste costs include the cost of wood waste, the transportation of wood waste, fuel and management costs and the disposal of wood ash. Although wood waste and the related transportation services have been purchased under contract for the majority of the fuel requirements at the Calstock and Williams Lake facilities, the suppliers have no obligation to provide in the event they scale back or shut down operations.

The Partnership purchases fuel gas and/or waste heat for each of the Ontario power plants except Tunis, under long-term natural gas and waste heat supply agreements. The Partnership reached an agreement with the OEFC to amend the Tunis PPA effective January 16, 2010 that allows the

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Partnership to flow-through natural gas and transportation costs in excess of benchmark amounts to OEFC and extends OEFC the right to curtail the plant during summer off-peak periods through the remaining term of the PPA in 2014. Firm capacity for the transportation of fuel gas to the Ontario power plants has been contracted for on the TransCanada natural gas transmission system under long-term transportation agreements, the earliest of which expires in 2011. See "Business Risks Energy Supply Risk" in the MD&A.

In late 2008, the Partnership completed a new supply agreement with a nearby wood waste landfill site for Calstock. The landfill site is estimated by management to have equivalent to one million green metric tons of supply, which is equal to three years of supply for the plant. Pursuant to a Certificate of Approval (CoA) from the Ministry of Environment, Calstock successfully completed a rail ties test burn in November 2009. The Partnership has applied for a permanent CoA amendment from the Ministry of Environment. If approved, the rail ties could provide up to 20% of the Calstock facility's fuel requirement.

Wood waste supply to the Williams Lake facility was sufficient in 2010. Traditional suppliers returned to near normal production levels with the exception of one supplier who continues to idle one of their sawmills. The Partnership has identified other sources of supply to replace volume lost from the curtailed sawmill. These sources are more expensive; however, approximately 82% of the fuel cost is borne by BC Hydro under the PPA. The facility is well positioned to withstand potential fuel shortages largely due to an agreement with Pioneer Biomass Inc. to supply processed forest based residuals, on an as needed basis, to the Williams Lake facility. Fuel inventory levels were reduced significantly in 2010 to bring back to normal operating levels. The expanded wood waste storage capacity continues to provide flexibility in managing available lower cost wood waste supplies. At December 31, 2010, the plant had sufficient wood waste inventory for the plant to produce its maximum output of 66 megawatts (MW) for 35 days at full output.

Natural gas supply purchased for the Greeley facility is financially fixed under an agreement with Shell Energy North America and CP Energy Marketing (US) Inc. which expires in October 2011. Natural gas for the Naval Facilities and Oxnard is purchased through natural gas contracts with RBS Sempra Energy Trading Corporation (Sempra) at monthly index prices similar to those used in the utility SRAC calculations. Kenilworth natural gas is also purchased from Sempra with that price used directly in the steam pricing under the ESA. The Morris facility obtains the majority of its required natural gas through a Purchase and Sale Agreement with DCP Midstream Marketing LP and Tenaska Power Services Co. (Tenaska) which expires in 2016 at a price indexed to the Chicago City Gate market. Under the agreement, Tenaska also provides power market trading services through a year-to-year agreement that may be cancelled on 60 days notice. Additionally, the Morris facility contracts gas storage facility as a seasonal hedge and to maximize operational flexibility.

Approximately 25-30% of the Southport and 20-24% of the Roxboro facilities' fuel requirements are satisfied with coal, with the balance from tire-derived fuel and waste wood. The anticipated coal requirements for 2011 for each facility are sourced with regional coal suppliers. Tire-derived fuel and waste wood are sourced from multiple local suppliers. Tire-derived fuel is procured under fixed-price contracts, and waste wood is procured at fixed prices indexed to the transport distance from the facility and subject to a fuel surcharge.

Partnership Waste Heat Agreements

Pursuant to long-term waste heat agreements, TransCanada provides the Ontario power plants with all waste heat generated by the natural gas turbine compressors located at the compressor stations adjacent to the Ontario power plants on an as available basis. Each agreement continues in effect for as long as the Partnership delivers electrical energy from the particular plant. The waste heat agreements provide that TransCanada will be obligated to supply waste heat to the Ontario power

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plants only when such waste heat is available from the compressor stations. In the event waste heat output is reduced at a compressor station as a result of reduced natural gas turbine output arising from any cause, TransCanada's obligation to deliver waste heat is reduced accordingly. See "Business Risks Energy Supply Risk" in the MD&A.

In 2003, the Partnership entered into an agreement with TransCanada to optimize the waste heat availability at certain of the Partnership's Ontario plants. Under the agreement, the Partnership pays for incremental natural gas used in the compressor station turbines to optimize the quantities of waste heat which can be available to the Partnership's adjacent power plant. Any incremental maintenance or repair costs as a result of the increased use of TransCanada's turbines are also charged to the Partnership.

PERC Management Arrangements

Pursuant to the PERC Management Agreement, the Partnership, through Ventures, provides management and administrative services to PERH and its subsidiaries and, if and to the extent requested by PERC, provides certain administrative services to PERC. The initial term of the PERC Management Agreement expires in 2025. In consideration for providing the management and administrative services, the Partnership receives a base annual management fee.

Concurrently with the PERH recapitalization in August 2009, certain changes were made to the PERC Management Agreement. The changes include: (i) PERH has assumed responsibility for certain management functions, (ii) the parties agreed that PERH can terminate the management agreement for a specified price, declining over time, if the Partnership agrees to sell its interest in PERH, and (iii) the allocation agreement among the Partnership, PERC and certain other parties, together with the rights of first offer in respect of certain projects of the Partnership granted to PERC and to PERH under the PERC Management Agreement and the allocation agreement, have been terminated. See "General Development of the Business Three Year History".

PERC, through PERH and its subsidiaries, competes with the Partnership. The PERC Management Agreement does not prohibit the Partnership or its affiliates from competing with PERC or PERH or from acquiring, investing in, or providing administrative or managerial services to a competitor of PERC. Pursuant to the PERC Management Agreement, PERC, PERH and its subsidiaries acknowledge and agree that the Partnership and its affiliates may engage in activities similar to and competitive with those of PERC, PERH and its subsidiaries.

Employees of the Partnership

Neither the Partnership nor the General Partner has any employees. All day-to-day operations at the Canadian and U.S. power generation facilities are undertaken by employees of Capital Power with the exception of the Manchief facility. Operations and maintenance services for the Manchief facility are supplied by a contracted service provider, Colorado Energy Management, LLC.

All senior officers of the Partnership are employed by, and obtain all of their compensation from, Capital Power, and compensation for their services to the Partnership is paid by Capital Power. The directors and officers of the Partnership who are officers or employees of Capital Power do not receive any compensation directly from the Partnership for such services. See "Compensation Discussion and Analysis".

The Canadian operations have approximately 23 non-unionized employees at North Bay, Mamquam and Moresby Lake. The facility operations at Nipigon, Kapuskasing, Tunis and Calstock unionized in the spring of 2006. The Power Workers' Union of Ontario is the certified bargaining agent for approximately 46 employees at these facilities and has a collective agreement with Capital Power which expires in December 2013. At the Williams Lake facility, there are approximately 23 unionized employees whose United Steel Workers local has a collective agreement with Capital Power which expires in December 2011. The United States operations have approximately 167 non-unionized employees.

Expansion, Enhancement and Acquisition Opportunities

Where opportunities arise, the Partnership will seek to grow its asset base by expanding capacity and implementing enhancements at existing plants and by pursuing acquisition or development opportunities that meet the Partnership's investment criteria and are accretive to cash flows. These criteria include generation assets that have relatively stable and predictable cash flows; risk profiles similar to the assets already owned by the Partnership; and with predictable capital expenditures and long operating lives.

The Ontario PPAs contain provisions that, under certain circumstances and subject to the consent of OEFC, allow for the sale of additional electricity to the extent that the plants subject to the agreements are physically expanded. Expansions could be achieved in a number of ways; however, at present there is no agreement with OEFC to expand the Ontario plants.

RISK FACTORS

The Partnership has direct ownership interests in a portfolio of 20 power generation assets that operate using six different fuel types in two countries, and also a 14.3% equity ownership interest in another organization that owns 5 plants, and is therefore subject to a number of business and operational risks.

A detailed discussion of risk factors is included in the section on "Business Risks" in the Partnership's MD&A dated March 2, 2011 and filed on SEDAR.

REGULATION

Set forth below is an overview of the principal electrical power regulatory regimes to which the Partnership's operations are subject. Environmental regulations affecting the Partnership's operations are discussed under "Environmental Regulation".

The Partnership's operations are subject to extensive regulation by governmental agencies. In addition to environmental regulation, the Partnership's facilities and operations are subject to laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, access to transmission, and the geographical location, zoning, land use and operation of a facility.

Ontario

The OEFC is one of five corporations established by the *Electricity Act, 1998*. OEFC is the purchaser of 100% of the power produced by the Partnership's operations in Ontario. This relationship has remained stable despite numerous regulatory and policy changes over the intervening years. The formation of the Ontario Power Authority (OPA) in 2004, while having no impact on the existing contracts, is helpful in that it will provide a creditworthy counterparty with whom to negotiate replacement PPAs as the existing agreements expire.

On September 20, 2010, the Ontario Minister of Energy announced a revised process regarding the development of the Integrated Power System Plan (IPSP). On November 23, 2010, the Ontario Ministry of Energy issued its "Long-Term Energy Plan" (LTEP) and a proposed new supply mix directive. Subject to a 45 day posting of the proposed supply mix directive on the Environmental Registry, the OPA will prepare a detailed IPSP, hold consultations, and submit a revised IPSP to the Ontario Energy

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Board (OEB) by mid 2011 with review by the OEB to take place between 2011 and 2012. Once reviewed and approved by the OEB, the IPSP will be updated every three years as required by regulation.

On October 7, 2010, the Ontario government announced that the 900 MW Oakville Generating Station selected by the OPA for the southwest Greater Toronto Area was no longer required and would be cancelled. The LTEP issued on November 23, 2010 referenced this cancellation but noted that natural gas would continue to play a strategic role in Ontario's supply mix by complementing intermittent supply from renewable energy projects, meeting local and system requirements, and ensuring that adequate capacity is available as nuclear plants are modernized, and that the OPA will continue to plan on natural gas usage for those strategic purposes. The LTEP specifically noted that the procurement of a natural gas-fired plant in the Kitchener-Waterloo-Cambridge area, as was originally envisaged in the original IPSP submitted to the OEB in 2007, is still necessary to ensure adequate regional electricity supply.

British Columbia

BC Hydro is the principal purchaser and distributor of electricity in the Province of British Columbia. BC Hydro is owned by the Province of British Columbia and is regulated by the British Columbia Utilities Commission (BCUC). The British Columbia Government Energy Plan (BC Energy Plan) and direction to BC Hydro have the effect of making hydroelectric, wind and wood waste electricity generation more favourable than natural gas and coal fired electricity generation.

On August 27, 2009, the Government of British Columbia affirmed that development of clean and renewable energy sources will continue to be aggressively promoted and pursued in conjunction with energy self-sufficiency both to support achievement of British Columbia's climate action plan goals and to position British Columbia as a "clean energy powerhouse" as per the BC Energy Plan.

On April 28, 2010, the Government of British Columbia introduced a new Clean Energy Act that aims to aggressively accelerate and expand development of clean and renewable energy sources within the Province of British Columbia to achieve energy self-sufficiency, job creation and greenhouse gas reduction objectives. The Clean Energy Act also re-integrates British Columbia Transmission Corporation (BCTC) into BC Hydro and provides a new role for BC Hydro to actively market and expand sales of BC clean power in export markets. The Clean Energy Act received Royal Assent on June 3, 2010, and BCTC was re-integrated into BC Hydro effective July 5, 2010.

The Clean Energy Act requires BC Hydro to submit an Integrated Resource Plan (IRP) by November 2011. The long-term electricity planning framework and expanded opportunities for contracted power development for both BC domestic use and BC Hydro export purposes established through the Clean Energy Act, and addressed through the forthcoming IRP, could provide opportunities for the Partnership. The Clean Energy Act would also streamline regulatory approval processes for future projects qualifying for contracts with BC Hydro.

U.S. Energy Industry Regulatory Matters

Federal Energy Regulatory Commission (FERC) Jurisdiction

Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of electric energy in interstate commerce is a public utility subject to FERC's jurisdiction. FERC has extensive ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the Federal Power Act (FPA) and with respect to certain interstate sales, transportation and storage of natural gas under the U.S. Natural Gas Act of 1938 (NGA), as amended and the U.S. Natural Gas Policy Act of 1978 (NGPA), as amended. FERC also maintains certain reporting requirements for public utilities and regulates, among other things, the

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disposition and acquisition of certain assets and securities, the holding of certain interlocking directorate positions, and the issuance of securities by public utilities.

Transmission Service

Issued in 1996, FERC Order No. 888 mandated the unbundling of utilities' transmission and generation services and required such utilities to offer eligible entities open access to utility transmission facilities on a basis comparable to the utilities' own use of the facilities. FERC Order No. 888 required public utility transmission owners to file open access transmission tariffs containing the terms and conditions under which they would offer transmission service, enabling independent generators and marketers to schedule and reserve capacity on those transmission facilities. In 2007, FERC Order No. 890 made a number of changes to open access implementation, including requiring an open, transparent and coordinated transmission planning process on both a local and regional basis.

In 1999, FERC issued Order No. 2000, which set out standards for Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). These organizations are operated by an entity that is independent of market participants, and planning, operations, and transmission services are performed on a regional instead of utility specific basis. In addition, most ISOs and RTOs administer liquid day-ahead and real-time spot markets. Examples are PJM Interconnection, ISO New England, New York ISO, Midwest Independent Transmission System Operator and California ISO. In 2008, FERC Order No. 719 made incremental reforms to such markets, including requiring scarcity pricing to encourage demand response and other new resources.

Market-Based Rate Authority

Under the FPA and FERC's regulations (subject to certain exceptions for entities such as municipal utilities that are not public utilities under the FPA), an entity seeking to make wholesale sales of power at market-based or cost-based rates must obtain authorization from FERC. FERC grants market-based rate authorization if it finds that the seller and its affiliates lack market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and the seller and its affiliates comply with certain affiliate restrictions. All of the Partnership's affiliates that own power plants in the U.S. (except for those power plants that are QFs, as well as the Partnership's power marketer affiliates, are currently authorized by FERC to make wholesale sales of power at market-based rates. This authorization is subject to revocation by FERC if such companies fail to continue to satisfy FERC's current or future criteria for market-based rate authority or to modification if FERC restricts the ability of wholesale sellers of power to make sales at market-based rates.

Mergers and Acquisitions

FERC has FPA jurisdiction over certain sales, mergers, consolidations and acquisitions of public utility assets or securities, and over certain mergers and acquisitions involving holding companies and transmitting utilities or electric utility companies. In reviewing such matters, FERC reviews the effect of the transaction on competition, rates and regulation and ensures that there is no unlawful cross subsidization of affiliates by entities with captive customers.

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)

ISOs grew out of Orders Nos. 888/889 where the Commission suggested the concept of an ISO as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, the Commission encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America. With the exception of the southeast and northwest, most wholesale power markets in the lower 48 states of the

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United States are controlled by RTOs operating under FERC jurisdiction. The organized markets under each of these RTOs have developed differently, each with their own variation of markets. The northeast region (PJM, NYISO and ISO-NE) is considered the more developed of the RTOs but each region has its own uniqueness of history, market participants, resources and state involvement. Market rules continue to evolve. The non-organized market regions of the northwest and southeast typically represent the old model of vertically integrated utilities and opportunities there are limited to bilateral contracts.

Reliability Standards

Pursuant to the U.S. Energy Policy Act of 2005, FERC finalized in February 2006 new rules regarding the certification of an Electric Reliability Organization and the procedures for the establishment, approval and enforcement of mandatory electric reliability standards. In July 2006, FERC certified North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization to establish and enforce reliability standards applicable to all owners, operators and users of the bulk power system. NERC relies on regional reliability entities to enforce FERC and NERC standards with bulk power system owners, operators, and users through approved delegation agreements. Such regional entities are responsible for monitoring compliance of the registered entities within their regional boundaries, assuring mitigation of all violations of approved reliability standards and assessing penalties and sanctions for failure to comply.

FERC Enforcement Authority

FERC has the authority to enforce the statutes it is responsible for implementing and the regulations it issues under those statutes. The U.S. Energy Policy Act of 2005 conferred substantial enforcement authority on FERC, allowing it to impose civil penalties of up to U.S. $1 million per day per violation for violations of the NGA, NGPA and Part II of the FPA. This expanded penalty authority also applies to any entity that manipulates wholesale natural gas or electric markets by engaging in fraud or deceit in connection with jurisdictional transactions. In addition, these laws allow for the assessment of criminal fines and imprisonment for violations.

The Public Utility Regulatory Policies Act of 1978

The Public Utility Regulatory Policies Act of 1978, as amended (PURPA) and FERC's regulations under PURPA provide certain incentives for the development of combined heat and power facilities and small power production facilities using alternative or renewable fuels, in part by establishing certain exemptions from the FPA and the U.S. Public Utility Holding Company Act of 2005 for owners of QFs.

PURPA provides two primary benefits to QFs. First, all cogeneration facilities, geothermal and biomass small power production facilities, and small power production facilities 30 MW or smaller that are QFs are exempt from certain provisions of the FPA, the regulations of FERC thereunder and the U.S. Public Utility Holding Company Act of 2005. Second, the FERC regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs that are directly, or under certain circumstances indirectly, connected to such electric utilities at a price based on the purchasing utilities avoided cost and that such utilities sell back up power to such QFs on a non-discriminatory basis. An electric utility may be entitled to relief from these mandatory purchase and sale obligations if, in the case of the mandatory purchase obligation, the utility can show that the QF has non-discriminatory access to a market that meets certain competitive conditions and, in the case of the mandatory sale obligation, if the utility can show that that there are competing retail electric suppliers willing and able to sell and deliver electricity to the QF and there is no obligation under state law for the utility to make such power sales. The provisions for relief from the mandatory purchase and sale obligations do not affect contracts entered into or pending approval on or before August 8, 2005.

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Under FERC's regulations, QFs are subject to FERC's rate making authority under the FPA and are required to obtain market-based rate authority in order to sell power at market-based rates, except for sales of energy or capacity: (i) made by QFs that have a generating capacity of 20 MW or less; (ii) made pursuant to a contract executed on or before March 17, 2006; or (iii) made pursuant to state-approved avoided cost rates.

PURPA establishes certain thermal use and efficiency requirements for QFs. Loss of a steam host or changes in operations at the facility or at the steam host may result in non-compliance with such requirements. The Partnership endeavours to monitor regulatory compliance by its QF facilities in a manner that minimizes the risks of losing these facilities' QF status. If any of the QF facilities in which the Partnership has an interest were to lose its status as a qualifying cogeneration facility, that facility would no longer be entitled to the QF-related exemptions and could become subject to rate regulation under the USFPA and additional state regulation. Loss of QF status could also trigger defaults under covenants to maintain QF status in the facilities' PPAs, SPAs and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements. Loss of QF status on a retroactive basis could lead to, among other things, fines and penalties, or claims by a utility customer for the refund of payments previously made. If the obligation to purchase from some or all of the Partnership's QFs is terminated, the Partnership will seek alternative purchasers for the output of such QFs or enter into negotiated rate contracts with existing counterparties once their current contracts expire. Such sales will be at prevailing market rates, which may not be as favourable as the terms of the PURPA sales arrangements under existing contracts and thus may diminish the value of the Partnership's QFs.

In November 2007, FERC granted a limited request for waiver of FERC's QF operating and efficiency standards for the Roxboro facility due to an inability to find a replacement steam host. On January 1, 2010 Roxboro was recertified as a QF under the requirement for a Small Power Producer due to its ability to utilize renewable fuel.

Public Utility Holding Company Act of 2005

In August 2005, the passage of U.S. Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 and enacted the U.S. Public Utility Holding Company Act of 2005, effective February 2006, which primarily addresses FERC's access to the books and records of holding companies. Any entity that is a holding company solely with respect to QFs, exempt wholesale generators or foreign utility companies, such as the Partnership, is exempt from FERC's books and records requirements and any accounting, record-retention and reporting requirements contained in the U.S. Public Utility Holding Company Act of 2005 and FERC's regulations promulgated thereunder.

California

The Naval Facilities in San Diego and the Oxnard facility in Oxnard sell energy to SDG&E and SCE respectively on the basis of each utility's SRAC formula.

On September 20, 2007, the CPUC accepted an alternative decision regarding revisions to the SRAC cost formulae that were implemented in 2009. The essence of the decision is to provide a 50/50 split between market and administrative heat rates for the calculation of the overall heat rate used in the compensation calculation. This increases the amount of variable operating cost included in the determination of SRAC amount. The SRAC change impacts the steam payment component of the PPAs described above and the Partnership is currently in discussion with the Navy on implications of future steam pricing.

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Colorado

On April 19, 2010, the Colorado Legislature enacted House Bill 10-1365 (HB1365) which entitled the "Clean Air-Clean Jobs Act" (CACJA). CACJA requires PSCo to submit a plan to the Colorado Public Utilities Commission (CoPUC) to achieve 70 - 80% reductions in NOx emissions from a minimum of 900 MW of its existing coal generating facilities by December 31, 2017 with a CoPUC decision accepting, modifying or rejecting the plan required by December 15, 2010.

The specific replacement options that will ultimately be approved for PSCo could have implications for future commercial contracting opportunities for the Partnership's Greeley facility. The existing Greeley PPA with PSCo expires in August 2013.

The CoPUC issued a decision on December 15, 2010. The CoPUC did not select any of the packaged portfolios that were extensively modeled in the docket, but instead generated its own unique plan that incorporates elements of various plans. The decision directs PSCo to retire 551 MW of existing coal generation, add emissions controls to 742 MW of existing coal capacity, fuel-switch 463 MW of coal-capacity to natural gas, and construct a new 2x1 natural gas combined cycle facility with 569 MW capacity. The CoPUC did acknowledge other options, including gas turbines, IPP generation, and transmission, may be more effective long-term solutions than fuel-switching coal-to-natural gas units, and in this respect directed PSCo to present alternatives to fuel-switching coal-to-natural gas in its upcoming ERP due in late 2011.

The decision preserves an option for the Partnership and other existing IPP facilities to bid into the next RFP. On January 4, 2011, seven parties, including PSCo and CIEA (on behalf of the Partnership and SWG), filed "Requests for Rehearing, Reargument or Reconsideration" (RRR Request) regarding various aspects of the decision. See "Legal Proceedings".

ENVIRONMENTAL MATTERS

The Partnership has obtained all environmental licenses, permits, approvals and other authorizations required for the operation of its power plants. Except as outlined below, the Partnership is satisfied that its operating practices are in material compliance with applicable environmental laws and regulatory requirements. The power plants are operated in an environmentally sound manner and the environmental management systems are aligned with the corporate policies and procedures of Capital Power, which are binding upon the General Partner and the Manager.

At the Calstock plant, opacity remains a concern while burning the landfill waste wood alone. A blend of fuel supply is utilized to mitigate opacity and particulate issues. However, Calstock is not meeting two other conditions in its Certificate of Approval (CoA): (i) attaining the minimum combustion gas temperature and residence time, and (ii) the maximum carbon monoxide concentration in the stack. The Partnership has submitted an application to the Ontario Ministry of Environment to amend the Certificate of Approval to more accurately reflect the operating conditions of the plant.

Environmental Regulation

Many of the Partnership's operations are subject to extensive environmental laws, regulations and guidelines relating to the generation and transmission of electricity, pollution and protection of the environment, health and safety, greenhouse gas (GHG) and other air emissions, water usage, wastewater discharges, hazardous material handling, storage, treatment and disposal of waste and other materials and remediation of sites and land-use responsibility. These regulations can impose liability for compliance costs and costs to investigate and remediate contamination.

The Partnership business is a significant emitter of carbon dioxide (CO_2), NOx, sulphur dioxide (SO_2), mercury and particulate matter (PM), and is required to comply with all licenses and permits and federal, provincial and state requirements, including programs to reduce or offset GHG emissions.

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Compliance with new regulatory requirements may require the Partnership to incur significant capital expenditures or additional operating expenses, and failure to comply with such regulations could result in fines, penalties or the curtailment of operations. To the extent that proposed regulations are described below, until detailed regulations are enacted there is insufficient information to assess the impact on the Partnership, although as additional regulations are passed it is likely the Partnership will incur increased costs.

Canadian Federal Government GHG Emissions Regulations

On June 23, 2010, the Canadian Environment Minister announced the Government of Canada's plan for new GHG emission regulation for coal-fired electricity generation units. The proposed plan will apply a new GHG emissions performance standard to new coal-fired electricity generation units and facilitate phasing out conventional coal-fired electricity generation in an orderly manner. The regulations are anticipated to be effective July 1, 2015 and units that have commercial operation dates prior to July 1, 2015 are expected to be exempt from the regulation until they reach the end of their economic useful life. Because the proposed regulations address coal-fired generation assets they are not expected to have any negative impact on the Partnership's facilities.

Canadian Federal Government Air Emission Regulations

The Canadian government is considering regulations which may place stricter limits on NOx, SO_2, mercury and PM emissions from fossil fuel-fired generating stations in Canada. The Canadian Department of Environment has been working with the provincial governments and industry to develop a regulatory framework to minimize local emissions under a Comprehensive Air Management System (CAMS) and the regulations are expected to be implemented in 2013.

Ontario

The Ontario government aims to harmonize its cap and trade program with the Western Climate Initiative (WCI), which is represented by four provinces (B.C., Ontario, Quebec and Manitoba) and seven states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington). The WCI requires a 15% reduction in GHG emission levels by 2020, from those of 2005. The cap and trade system applicable to industrial facilities including electricity generation is expected to be implemented in 2012. However, the Ontario Government has not yet provided the industry specific GHG reduction targets or other program details.

British Columbia

The Greenhouse Gas Reduction Targets Act and the *Greenhouse Gas Reduction (Cap and Trade) Cap and Trade Act* which were enacted in 2008, provide the statutory basis for establishing a market-based framework to reduce GHG emissions from large emitters. The BC Government aims to harmonize its cap and trade program with the WCI, similar to Ontario. The cap and trade system applicable to industrial facilities including electricity generation is expected to start in 2012 and will replace the current fuel tax. However, the BC Government has not yet provided the industry specific GHG reduction targets or other program details.

U.S. Greenhouse Gas Regulation

The U.S. Environmental Protection Agency (USEPA) and the state of California have implemented mandatory GHG reporting requirements, which are expected to be met by the Partnership on their respective due dates in 2011.

The USEPA is expected to regulate GHGs under the *Clean Air Act* (CAA) with requirements for best available control technology for new GHG sources and major modifications of existing sources.

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They also plan to control GHG emissions for existing and new sources through new source performance standards.

The WCI, as described above under Ontario, may affect the operation of the Partnership's four facilities in California and the Frederickson facility in Washington.

California's proposed Cap and Trade program to control GHGs aims to cut the state's GHG emissions to 1990 levels by 2020 with further reductions each year thereafter. The initial phase of the program will apply to electric generation and large industrial units and is expected to be effective in January 2012, but the proposal's GHG emission allocation methodology has not yet been established. On November 2, 2010, a proposition (Proposition 23) to effectively repeal the program was rejected by California voters.

There is currently insufficient information to determine the impact of the proposed regulations on the Partnership, however if additional regulations are passed it is likely that the Partnership will incur increased costs.

U.S. Air Emission Regulations

In July, 2010, USEPA proposed the *Clean Air Transport Rule* (CATR) to replace the Clean Air Interstate Rule. CATR proposes to reduce the amount of Nitrogen Oxide (NOx) and Sulphur Dioxide (SO_2) emissions from electric generating units that are transported in the air to down-wind states. CATR proposes emission reductions sufficient to contribute to reducing NOx and SO_2 measures below the ambient air quality standards in those down-wind states. The CATR proposals are also expected to significantly limit emissions trading.

CATR only applies to units of generating facilities with a capacity of 25 MW or more, although it may be extended to other facilities when it is re-evaluated in 2014. Cogeneration facilities and units not providing electricity for sale on the electricity grid are also exempt. The Partnership units that may be impacted are Roxboro, Southport, and Morris, however, there is insufficient information to understand the implications of the proposed regulations.

There is currently insufficient information to determine the impact of these air emission proposed regulations on the Partnership, however if additional regulations are passed it is likely that the Partnership will incur increased costs.

In 2010, the USEPA proposed new air toxics standards, including standards for mercury, for industrial boilers (Boiler MACT) and for coal and oil-fired electric generating units. However, the state of North Carolina issued a maximum available control technology permit to the Partnership under the CAA, which precludes the application of these proposed new standards to its North Carolina facilities. In addition, based on the fuel mix and newly installed controls at the Partnership's North Carolina facilities, the Partnership does not anticipate the need for further mercury or other hazardous emissions controls at these facilities.

U.S. Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)

CERCLA, also referred to as Superfund, requires investigation and remediation of sites where there has been a release or threatened release of hazardous substances. It also authorizes the USEPA to take response actions at Superfund sites, including ordering parties who are potentially responsible for the release to pay for their actions. Many states have similar laws. CERCLA defines potentially responsible broadly to include past and present owners and operators, as well as generators, of wastes sent to a site. The Partnership is currently not subject to any material liability for any Superfund matters. However, the Partnership generates certain wastes, including hazardous wastes, and sends certain of its wastes to third party waste disposal sites. As a result, there can be no assurance that the Partnership will not incur a liability under CERCLA in the future.

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COMPETITION

During the terms of the PPAs, the obligations to purchase power generated by the power plants are firm up to the contract quantities and are not significantly affected by a competitive market for power in the jurisdictions and markets in which the power plants are located or the markets to which their power is sold. At the Williams Lake plant, any excess energy, approximately 20% of the total energy produced, is priced by reference to a power index. In 2009, the year end excess energy price ($58/MWh) was higher than the year end prices received for such excess energy in 2008 ($49/MWh). Except in that limited instance, (e.g. Williams Lake excess energy), the potential presence of lower or higher priced power in any of the electricity markets supplied by the power plants does not (subject to certain curtailment rights in the applicable PPAs), allow for a change either in the quantity of power required to be purchased under such agreements or the price payable for such power. During the term of a SPA, the obligations to purchase steam and other forms of thermal energy generated by the CHP facilities are fixed by the contract. While some areas may offer ready access to an alternate steam or thermal energy source, most would require the construction of new facilities and infrastructure by the customer or another third party to offer a competing supply. It is a competitive advantage to the CHP facilities to have their facilities and infrastructure in place and available to the customer.

Ongoing research and development activities improve upon power technologies and reduce the cost of alternative methods of power generation. As the PPAs and SPAs expire the Partnership must re-contract plant capacity which may also involve capacity re-powering or upgrades in order to compete with more efficient plants utilizing newer technologies.

Competition in the North American power generation market is comprised of numerous fully and partially-regulated utilities and independent power producers. However, with operational experience in four types of energy supply, a broad geographic footprint and good access to capital markets, the Partnership is well-positioned to compete for contracted generation assets.

Canada

In its 2009 outlook of Canada's energy supply, the National Energy Board of Canada forecasts Canadian electricity production to grow at a compound average annual rate of over 1% between 2011 and 2020. The combined effect of demand growth and facility retirements is expected to result in a need for new generation in the coming years. The British Columbia and Ontario markets remain price regulated, and provincial regulatory bodies have continued to issue RFP's or other procurements for the development of new generation.

United States

The U.S. Energy Information Administration in its 2010 Annual Energy Outlook forecasts U.S. electricity demand to grow at a compound average annual rate of over 1% between 2011 and 2020. In combination with limited near-term capacity development and anticipated retirements (particularly of aging coal plants), demand growth in the U.S. is expected to compress reserve margins and necessitate renewed development activity. Regional power markets within the U.S. exhibit a high level of diversity, due in part to differing regulatory regimes, transmission constraints, supply and demand characteristics and environmental policies. The U.S. market has solid growth potential for the Partnership due to its size relative to the Canadian market and because of its historical reliance on fossil fuel-based power generation which is an area of expertise for the Partnership.

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DISTRIBUTIONS OF THE PARTNERSHIP

Cash distributions per Unit declared by the Partnership per year during the past three years are as follows:

	2010	2009	2008
Cash distributions per Unit declared per year	$ 1.76	$ 1.95	$ 2.52

Prior to October 1, 2009, the Partnership distributed cash to its limited partners on a quarterly basis. Commencing after September 30, 2009 the Partnership distributes cash to its limited partners on a monthly basis in accordance with the requirements of the Partnership Agreement and subject to the approval of the Board of Directors of the General Partner. Cash distributions are determined in consideration of cash amounts required for the operations of the Partnership and the power plants including maintenance capital expenditures, debt repayments, and financing charges, and any cash retained at the discretion of the Board of Directors of the General Partner to satisfy anticipated obligations or to normalize monthly distributions. The cash distributions are made in respect of each calendar month to Unitholders of record on the last day of each month commencing after September 30, 2009. Payments are made on or before the 30th day after each record date. See "General Development of the Business". In connection with the signing of the Memorandum of Agreement, the Partnership announced a reduction in distributions on Units from $0.63 per Unit per quarter to $0.44 per Unit per quarter effective with the June 2009 distribution. Distributions are prohibited by certain covenants under the Partnership's credit facilities, and pursuant to guarantees entered into in connection with the issue of preferred shares by CPEL, if an uncured default exists. See "Business Risks Preferred Share guarantee unit distribution risk" in the MD&A.

In October 2009, the Partnership announced the launch of a Premium Distribution™ and Distribution Reinvestment Plan (the Plan) that provides eligible Unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional Units in the Partnership by reinvesting cash distributions in additional Units issued at a 5% discount to the Average Market Price of such Units (as defined by the Plan) on the applicable distribution payment date. Under the Premium Distribution™ component of the Plan, eligible Unitholders may elect to exchange these additional Units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date. See "General Development of Business".

™ Denotes a trademark of Canaccord Capital Corporation

Additional information with respect to the Plan is available on the Partnership's website at www.capitalpowerincome.ca.

DIVIDENDS OF SUBSIDIARY (CPEL)

Series 1 Shares

Cash dividends per share declared by CPEL per year with respect to the Series 1 Shares during the past three years are as follows:

	2010	2009	2008
Cash dividends per share declared per year	1.2125	$ 1.2125	$ 1.2125

Series 1 Shares pay cumulative dividends of $1.2125 per share per annum payable quarterly on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of CPEL.

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Series 2 Shares and Series 3 Shares

CPEL paid an initial dividend of $0.28288 per share on December 31, 2009 on its Series 2 Shares for the period from November 2, 2009 to December 31, 2009. CPEL paid a fixed dividend of $1.75 per share per annum, payable quarterly, for the period from January 1, 2010 to December 31, 2010.

Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum payable quarterly on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of CPEL, for an initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The holders of Series 2 Shares will have the right to convert their shares into Series 3 Shares of CPEL, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board of Directors of CPEL, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%.

CPEL confirms that the dividends for Series 1 Shares and Series 2 Shares are 100% eligible dividends as defined by the *Income Tax Act* (Canada) (Tax Act). Under this legislation, individuals resident in Canada may be entitled to enhanced dividend tax credits that reduce the income tax otherwise payable.

CAPITAL STRUCTURE

The Partnership is authorized to issue an unlimited number of Units and an unlimited number of subscription receipts exchangeable into Units. Any limited partner who holds Units has represented, warranted and covenanted under the Partnership Agreement that they are not a non-resident of Canada for purposes of the Tax Act or, if a partnership, is a Canadian Partnership under the Tax Act. The Partnership Agreement itself contains restrictions on Unit ownership outside of Canada. The limited partners have further covenanted not to transfer their Units to any person including corporate or other entities which are not able to give these representations, warranties or covenants. Compliance with these covenants is monitored by regular review of a registered Unitholder list provided by the Partnership's transfer agent. Distributions will be withheld from non-residents.

Nature of Units

Unitholders do not have the right to elect directors of the General Partner or to appoint auditors of the Partnership. In addition, Unitholders do not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions.

Votes of the Limited Partners

Generally there are no meetings of the limited partners as the Partnership Agreement requires Unitholder votes in only limited circumstances. CPI Investments, as the owner of all of the shares of the General Partner, elects the directors of the General Partner. However, under the Partnership Agreement, the General Partner or limited partners holding not less than 10% of the outstanding Units may request a meeting which shall be convened within 60 days of receipt of notice of the meeting. A quorum will consist of one or more limited partners present in person or by proxy holding at least 10% of the outstanding Units.

Extraordinary Resolutions (as defined in the Partnership Agreement) will be decided by a poll allowing one vote for each Unit held by the person present as shown on the record as a limited partner at the record date and for each Unit in respect of which the person is the proxy holder. Extraordinary

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resolutions of the Unitholders are required to approve certain matters, including certain amendments to the Partnership Agreement, in certain circumstances the removal or voluntary withdrawal of the General Partner as general partner, the dissolution of the Partnership, the sale, exchange or other disposition of all or substantially all of the property of the Partnership, and the waiving of any default on the part of the General Partner.

Ordinary resolutions will be decided by a show of hands unless otherwise required by the Partnership Agreement or a poll is demanded by a limited partner. Ordinary resolutions of the Unitholders are required to approve certain matters, including in certain circumstances the removal of the General Partner as general partner.

Securities laws in Canada and the rules of the TSX also provide Unitholders with the right to vote in certain circumstances, such as on the approval of "related party transactions", and on certain significant private placement and acquisition transactions.

Dissolution

In the event of dissolution, the General Partner (or, in specified circumstances, such other person as may be appointed by ordinary resolution) shall act as receiver and liquidator of the assets of the Partnership and shall provide for the payment of all liabilities of the Partnership and distribute the balance of assets remaining after payment of creditors to Unitholders proportionate to the number of Units held by them.

Preferred Shares of CPEL

CPEL is authorized to issue an unlimited number of Preferred Shares issuable in series, of which up to 5,750,000 Series 1 Shares, 4,000,000 Series 2 Shares and 4,000,000 Series 3 Shares have been authorized for issuance.

Except as required by law or in the conditions attaching to the Preferred Shares as a class, the holders of Series 1 Shares, Series 2 Shares and Series 3 Shares are not entitled to vote at any meeting of shareholders of CPEL, unless and until CPEL has failed to pay eight quarterly dividends and for as long as any such dividends remain in arrears.

On May 25, 2007, CPEL issued 5,000,000 Series 1 Shares for gross proceeds of $125 million. Pursuant to a guarantee indenture dated May 25, 2007 among the Partnership, CPEL and CIBC Mellon Trust Company, the Partnership agreed to fully and unconditionally guarantee the Series 1 Shares on a subordinated basis as to: (i) payment of dividends, as and when declared; (ii) payment of amounts due on redemption of the Series 1 Shares; and (iii) payment of amounts due on liquidation, dissolution or winding up of CPEL.

On November 2, 2009, CPEL issued 4,000,000 Series 2 Shares for gross proceeds of $100 million. The holders of Series 2 Shares will have the right to convert their shares into Series 3 Shares of CPEL, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. Pursuant to guarantee indentures each dated November 2, 2009 among the Partnership, CPEL and Computershare Trust Company of Canada, the Partnership agreed to fully and unconditionally guarantee the Series 2 Shares and Series 3 Shares on a subordinated basis as to: (i) the payment of the dividends, as and when declared; (ii) the amounts payable on a redemption of Series 2 Shares or Series 3 Shares for cash; and (iii) the amounts payable in the event of the liquidation, dissolution and winding up of CPEL.

The guarantee indentures for the Series 1 Shares, Series 2 Shares and Series 3 Shares provide that if, and for so long as, the declaration or payment of dividends on the Series 1 Shares, Series 2 Shares or Series 3 Shares is in arrears, the Partnership will not make any distributions on the Units. See "Business Risks Preferred Share guarantee unit distribution risk" in the MD&A.

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Debt Financing

Credit Facilities

The Partnership currently has in place approximately $365 million in total credit facilities consisting of three revolving credit facilities totalling $325 million with three Canadian chartered banks, a $20 million demand credit facility with a Canadian chartered bank and a US$20 million demand credit facility with a US tier 1 bank. Each of the revolving credit facilities is unsecured, bears interest at market rates and has two-year terms maturing in June 2012, September 2012 and October 2012, subject to extension. As at December 31, 2010, the combined Canadian dollar equivalent of $86.1 million was utilized under these facilities. Under the revolving credit facilities, the Partnership must maintain a debt-to-capitalization ratio of not more than 65% as at the end of each quarter. In addition, in the event the Partnership is assigned a rating of less than BBB+ by Standard & Poor's (S&P) and less than BBB (high) by DBRS Limited (DBRS), the Partnership must also maintain a ratio of EBITDA (earnings before interest, income taxes, depreciation and amortization as defined in the respective credit facilities) to interest expense of not less than 2.5 to 1.0, measured quarterly. If an event of default has occurred and is continuing under such facilities, the Partnership may not declare, make or pay distributions (subject to certain limited exceptions). As at December 31, 2010, the Partnership was in compliance with its financial covenants and was not in default under its revolving credit facilities. There are no similar financial covenants in the demand facilities. The demand credit facilities are unsecured and bear interest at floating rates plus a spread.

Medium Term Notes Program

On June 23, 2006, the Partnership issued $210 million of unsecured medium term notes (MTNs) under a note indenture (the Note Indenture) dated June 15, 2006. The $210 million principal amount of MTNs outstanding is due June 23, 2036 and bears interest at 5.95% per annum. The Note Indenture does not limit the aggregate principal amount of MTNs that may be issued thereunder. Additional MTNs maturing at varying dates and bearing interest at different rates, in each case as determined by the Partnership, may be issued under the Note Indenture. Under the Note Indenture, the Partnership must maintain a debt-to-capitalization ratio of not more than 65%.

Senior Notes

On August 15, 2007, CPUSGP, issued an aggregate of US$150 million principal amount of 5.87% Senior Notes due August 15, 2017 and an aggregate of US$75 million principal amount of 5.97% Senior Notes due August 15, 2019, each guaranteed by the Partnership. Under the terms of the Senior Notes, the Partnership must maintain a debt-to-capitalization ratio of not more than 65%.

RATINGS

Debt Ratings

The Partnership has been assigned a debt rating for the Partnership's Senior Notes by S&P and DBRS.

S&P has assigned the Partnership a credit rating of BBB (stable). The "BBB" rating is the fourth highest rating out of 10 rating categories for S&P's long-term issuer credit ratings. According to S&P, an obligor rated "BBB" has adequate capacity to meet its financial commitments. However adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The stable outlook reflects S&P's view that the Partnership will continue to generate relatively stable revenue and cash flow from its diversified portfolio of generating assets supported by PPAs largely with investment-grade off-takers and well-spread expiries.

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DBRS has assigned the Partnership's long-term debt a credit rating of BBB (high). This rating is DBRS's fourth highest of 10 categories. Long-term debt rated "BBB" by DBRS is of adequate credit quality. According to DBRS, protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. The assignment of a "high" or "low" modifier indicates the relative standing within the rating category. As a result of the announcement of the strategic review process, DBRS placed this rating under review with negative implications.

Stability Rating

The Partnership has also been assigned a Stability Rating by DBRS.

DBRS has assigned the Partnership a stability rating of STA-2 (low). STA-2 is the second highest of seven categories in DBRS's rating system for income fund stability. DBRS further subcategorizes each rating category by the designation high, middle and low to indicate where an entity falls within the rating category. According to DBRS, income funds rated STA-2 have very good distributions per unit stability and sustainability, exhibit performance that is only slightly below the STA-1 category, typically show above-average strength in areas of consideration, and possess levels of distributable income per unit that are not likely to be significantly negatively affected by foreseeable events. According to DBRS, income funds rated STA-2 are above average in many, if not most, areas of consideration.

Preferred Shares Ratings

The preferred shares issued by CPEL have been assigned Preferred Share Ratings by S&P and DBRS.

S&P has assigned the Series 1 Shares and Series 2 Shares a rating of P-3 (high). Such P-3 (high) rating is the ninth highest of twenty ratings used by S&P in its preferred share rating scale. According to S&P, a P-3 (high) rating indicates that, although the obligation has some quality and protective characteristics, the obligor faces major ongoing uncertainties, and exposure to adverse business, financial, or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitments.

DBRS has assigned the Series 1 Shares and Series 2 Shares a rating of Pfd-3 with a negative trend. The Pfd-3 rating is the third highest of six rating categories used by DBRS for preferred shares. According to DBRS, preferred shares rated Pfd-3 are of adequate credit quality and, while protection of dividends and principal is still considered acceptable for such preferred shares, the issuing entity of preferred shares with a Pfd-3 rating is considered to be more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. DBRS further subcategorizes each rating by the designation of "high" and "low" to indicate where an entity falls within the rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

Ratings Summary

Ratings are intended to provide investors with an independent assessment of the credit quality of an issue or an issuer of securities and such ratings do not address the suitability of a particular security for a particular investor. The ratings assigned to a security may not reflect the potential impact of all risks on the value of a security. The above ratings are not a recommendation to buy, sell or hold securities of the Partnership and may be subject to revision or withdrawal at any time by the applicable rating organization.

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MARKET FOR SECURITIES

The Units trade under the symbol CPA.UN.

Toronto Stock Exchange 2010 Trading Statistics:

Month	Unit Price High	Unit Price Low	Unit Price Close	Volume Traded
January	$ 17.24	$ 15.54	$ 16.76	1,809,591
February	$ 16.98	$ 15.91	$ 16.51	1,238,618
March	$ 18.43	$ 16.50	$ 17.82	1,763,684
April	$ 18.14	$ 16.80	$ 17.18	1,463,942
May	$ 17.31	$ 15.05	$ 16.67	1,773,034
June	$ 16.59	$ 15.38	$ 16.30	1,834,995
July	$ 17.90	$ 16.03	$ 17.68	1,470,997
August	$ 18.01	$ 16.96	$ 18.01	1,275,618
September	$ 18.85	$ 17.65	$ 18.75	1,433,610
October	$ 19.02	$ 17.81	$ 18.33	1,395,389
November	$ 18.54	$ 17.75	$ 17.91	1,497,626
December	$ 18.10	$ 17.11	$ 17.95	1,566,002

MANAGEMENT OF THE PARTNERSHIP

General

The business and affairs of the Partnership are managed by the General Partner pursuant to the Partnership Agreement. Management services are provided by the Manager, and its affiliates, for and on behalf of the General Partner and the Partnership's subsidiaries, pursuant to the Management and Operations Agreements, pursuant to which the Manager is to provide, perform, or cause to be provided and performed, management and administrative services for the Partnership and operations and maintenance services for the power plants. Such services include, without limitation, advice and consultation regarding the affairs of the Partnership, its business planning, support, guidance and policy making, general management services and the management and operation of the power plants. The Manager relies on its resources and those of its affiliates in providing services to the Partnership under the Management and Operations Agreements. See "Interests of Management and Others in Material Transactions".

Certain of the officers and directors of the Manager are also officers or directors of Capital Power, and/or the General Partner. The Management and Operations Agreements are generally long term and are reviewed by the Partnership's Independent Directors Committee from time to time. See "Interests of Management and Others in Material Transactions".

The Partnership Agreement sets out the rights and duties of the limited partners as well as the General Partner. Under its terms, the business of the Partnership is restricted to direct or indirect participation in the energy supply industry.

The Partnership Agreement contains other provisions important to Unitholders. A copy is available on the Partnership's website at www.capitalpowerincome.ca or upon request to the Corporate Secretary of the General Partner or under the Partnership's profile on SEDAR at www.sedar.com.

The General Partner

The General Partner was incorporated on February 13, 1997 under the *Canada Business Corporations Act*. The General Partner is a wholly-owned subsidiary of CPI Investments. EPCOR owns all of the 51 voting non-participating shares of CPI Investments and Capital Power owns all of the 49 voting, participating shares of CPI Investments. Pursuant to the Shareholder Agreement in respect of

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CPI Investments, Capital Power L.P. and EPCOR agreed that: (i) the board of directors of CPI Investments shall consist of three directors; and (ii) EPCOR is entitled to nominate one person for election to the board of directors of CPI Investments. Under the Partnership Agreement, the General Partner is prohibited from undertaking any business activity other than acting as General Partner of the Partnership.

BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

The Board of Directors of the General Partner has plenary power and is responsible for the stewardship of the Partnership. The Board of Directors' Terms of Reference provide that its primary responsibility is to foster the long-term success of the Partnership consistent with the requirements set out in the Partnership Agreement and the Board's fiduciary responsibility to the Unitholders. As part of its mandate, the Board has the responsibility to seek to ensure that management has identified the principal risks of the Partnership's business and has implemented appropriate systems and strategies to manage these risks.

The Partnership Agreement does not entitle Unitholders to elect directors of the General Partner but rather requires that at least three directors be independent of Capital Power or its affiliates and EPCOR or its affiliates provided Capital Power and its affiliates and EPCOR and its affiliates together own at least 30% of the issued and outstanding Units. Should Capital Power and its affiliates and EPCOR and its affiliates not maintain a 30% ownership holding in the Partnership (or such lower percentage, being not less than 20%, resulting from the issuance of Units other than to Capital Power and its affiliates or EPCOR and its affiliates), not less than four directors must be independent. Capital Power's (including its Affiliates) ownership is approximately 29.6% as a result of the issuance of Units to other Unitholders under the Partnership's distribution reinvestment plan, and so the board of directors of the General Partner must have at least three directors who are independent. The Board has determined that, notwithstanding the Partnership Agreement, it is appropriate and in the interests of Unitholders and good governance that an additional independent director, as defined under Canadian securities laws, be appointed to the General Partner's Board. The Board of Directors now consists of four independent directors, as defined under Canadian securities laws, three directors who are senior officers of Capital Power, and one director who is a former senior officer of Capital Power.

The four independent members of the Board of Directors are not members of management of Capital Power and are independent, as that term is defined in National Instrument 58-101 *Disclosure of Corporate Governance Practices* (NI 58-101). Under NI 58-101, a director is independent if he or she would be independent within the meaning of independence under Section 1.4 of National Instrument 52-110 *Audit Committees* (NI 52-110). Under NI 52-110, a director is independent if he or she has no direct or indirect material relationship with the Partnership. A material relationship is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a director's independent judgment. The Board has determined that each of the four independent directors is independent for the purpose of NI 58-101 on the basis that he does not have any relationship with the Partnership which could reasonably be expected to interfere with the exercise of his independent judgement. The Board has determined that each of the other directors is not independent for the purpose of NI 58-101 on the basis that each is a member of senior management of Capital Power.

Directors and Officers

The following tables set out the full name, province/state and country of residence, date of birth and office for each individual that was a director or officer of the Partnership as at December 31, 2010, as well as their principal occupations during the past five years.

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Directors

Name, Province/State and Country of Residence, and Date became a Director and Units held(1)(2)	Office Held and 2010 Board & Committee Meetings Attended	Principal Occupation During the Past Five Years	Director of Other Reporting Issuers
Graham L. Brown(8) Alberta, Canada December 12, 2008 Units held: Nil(5) Date of Birth: January, 1953	Director 11 of 13 Board	Senior Vice President, Operations of Capital Power Corporation from July, 2009; prior thereto, Senior Vice President of EPCOR USA Inc. from May 2008 to June 2009; prior thereto, Vice President, Operations of EPCOR USA Inc. from January 2007; prior thereto, Director, Eastern of EPCOR Regional from September 2005; prior thereto, Production Manager, Ontario Power Generation from 2003.	
Brian A. Felesky, CM, QC(3)(4)(10) Alberta, Canada June 18, 1997 Units held: Nil(5) Date of Birth: November, 1943	Director 13 of 13 Board 9 of 10 Independent Directors 5 of 5 Audit 20 of 20 Special	Counsel with Felesky Flynn LLP (law firm) from December 2006; prior thereto Partner of Felesky Flynn LLP.	Precision Drilling Corporation, RS Technologies Inc., Cequence Energy Ltd.
Allen R. Hagerman, FCA(3)(4)(6)(10) Alberta, Canada February 26, 2003 Units held: 16,873(5) Date of Birth: May, 1951	Director 13 of 13 Board 10 of 10 Independent Directors 5 of 5 Audit 3 of 3 Governance 20 of 20 Special	Executive Vice President of Canadian Oil Sands Limited (oil and gas) from April 2007 to present; prior thereto, Chief Financial Officer of Canadian Oil Sands Limited from June 2003.	Precision Drilling Corporation
Francois L. Poirier(3)(4)(10)(11) Ontario, Canada April 2, 2007 Units held: 3,100(5) Date of Birth: July, 1966	Director 13 of 13 Board 10 of 10 Independent Directors 5 of 5 Audit 20 of 20 Special	Part-time instructor at Schulich School of Business (York University) from September 2007 to 2009; prior thereto, Managing Director and Group Head, Power Investment Banking Division, JP Morgan Securities, Inc., (financial services) from August 2005; prior thereto, Managing Director, Power Investment Banking from May 2001.	

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Name, Province/State and Country of Residence, and Date became a Director and Units held(1)(2)	Office Held and 2010 Board & Committee Meetings Attended	Principal Occupation During the Past Five Years	Director of Other Reporting Issuers
Brian T. Vaasjo(6) Alberta, Canada August 31, 2005 Units held: 7,400(5) Date of Birth: August, 1955	Chairman and Director 13 of 13 Board 3 of 3 Governance	President and Chief Executive Officer of Capital Power Corporation from July 2009 to present; prior thereto, Executive Vice President of EPCOR Utilities Inc. from April 2005; prior thereto, Executive Vice President and President, Energy Services for EPCOR Utilities Inc. from July 2001.	Capital Power Corporation
Rodney D. Wimer(4)(6)(10) Oregon, U.S. January 17, 2006 Units held: Nil(5) Date of Birth: August, 1949	Director 13 of 13 Board 10 of 10 Independent Directors 3 of 3 Governance 19 of 20 Special	Managing Director of Mazama Capital Partners LLC (private investments and asset management) since October 2002; General Partner of Fulcrum Power Services L.P. from October 2002 to September 2009 and a director from October 2002 to December 2010; prior thereto, President, Commercial Power Division of Dynegy Inc. (energy marketing) from March 2001 to January 2002.	Fairborne Energy Ltd.
James Oosterbaan(9) Alberta Canada June 24, 2009 Units held: Nil(5) Date of Birth: February, 1960	Director 13 of 13 Board	Senior Vice President, Commercial Services of Capital Power Corporation from July 2009; prior thereto, Senior Vice President of EPCOR Merchant & Capital and EPCOR Alberta from April 2004.	
Stuart A. Lee(7)(11) Alberta, Canada February 22, 2010 Units held: 3,536(5) Date of Birth: June, 1964	Director and President 13 of 13 Board	Senior Vice President, and Chief Financial Officer of Capital Power Corporation and President of CPI Income Services Ltd. from July 2009 to present; prior thereto, Chief Financial Officer of EPCOR Power Services Ltd. (now CPI Income Services Ltd.) from September 2005 and Vice President and Controller of EPCOR Utilities Inc. from July 2003 to July 2009.	

(1) The Board does not have an executive committee.

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(2) Directors are elected until the close of the next annual meeting of the shareholder of the General Partner, or the effective date of a resolution in writing of the shareholder of the General Partner removing the directors from office, or the effective date of their resignation in writing in lieu thereof.

(3) Member of the Audit Committee.

(4) Independent Director and Member of the Independent Directors Committee. The other Directors are Officers of Capital Power and are therefore not Independent Directors under applicable Canadian securities law.

(5) Represents as of December 31, 2010 the number of Units of the Partnership beneficially owned, or controlled or directed, directly or indirectly, by such persons. See "Director Compensation".

(6) Member of the Governance Committee.

(7) Mr. Lee was appointed as Director effective February 22, 2010.

(8) Mr. Brown retired effective January 4, 2011 from his position as Senior Vice President, Operations of Capital Power Corporation.

(9) Mr. Oosterbaan was appointed Senior Vice President, Operations & Commodity Portfolio Management of Capital Power Corporation on January 4, 2011.

(10) Member of the Special Committee.

(11) Member of the Strategic Review Sub-Committee.

Additional biographical information regarding the current directors of the General Partner is set forth below.

Brian T. Vaasjo

Brian Vaasjo has been President and Chief Executive Officer of Capital Power Corporation since July, 2009. Mr. Vaasjo was Executive Vice President of EPCOR Utilities Inc. until July, 2009, and was President of EPCOR's Energy Division from July, 2001 to April, 2005. Mr. Vaasjo was chiefly responsible for regional power generation and water operations. One of his primary responsibilities was advancing the company's competitive power and water businesses across North America including the clean coal initiatives. Mr. Vaasjo was also President of the Partnership from September 2005 until July 2009. Mr. Vaasjo is currently the Chair and a director of the General Partner.

Mr. Vaasjo joined EPCOR in 1998 as Executive Vice President and Chief Financial Officer. Mr. Vaasjo led EPCOR's initial public offering of debentures and preferred shares. After joining EPCOR, Mr. Vaasjo was responsible for EPCOR's development and acquisition activity for most of his tenure with EPCOR, including the Genesee 3 project and the UE Waterheater Income Fund spin-off. Before joining EPCOR, Mr. Vaasjo spent 19 years with the Enbridge Group of Companies. At Enbridge, Mr. Vaasjo led or played a substantial role in the Consumers Gas acquisition, development of the Alliance and Vector Natural Gas Pipelines and the initial public offering of the Lakehead Pipeline Partners LP among other initiatives.

Mr. Vaasjo holds a Master of Business Administration from the University of Alberta where he also received his undergraduate degree. Mr. Vaasjo is a Fellow of the Society of Management Accountants. Mr. Vaasjo also attended the University of Western Ontario Executive Program. In addition, he is a past Chairman of the board of the United Way, Alberta Capital Region, and a member of the Financial Executives Institute of Canada and is a board member for the Alberta Shock Trauma Air Rescue Society.

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Graham L. Brown

Mr. Brown was Senior Vice President, Operations of Capital Power Corporation until his retirement on January 4, 2011. Prior to becoming Senior Vice President, Operations of Capital Power Corporation, Mr. Brown joined what is now CP Regional Power Services Limited Partnership as Director of Eastern Operations in 2005 where his chief role included maximizing plant revenues while improving efficiency, safety and environmental compliance. In November 2006, the Partnership purchased Ventures where his experience in managing hydro, solid fuel, natural gas turbine and renewable energy plants proved highly valuable as he assumed the role of Vice President of Operations for Ventures in January 2007.

Mr. Brown began his career at GEC Gas Turbines Ltd. in Leicester, England in 1975 where he spent seven years building, operating and maintaining natural gas turbine power plants and gas pumping stations in the United Kingdom, Europe and the U.S. In 1982, he immigrated to Canada to join Ontario Hydro (subsequently Ontario Power Generation) and was involved in power operations for the next 23 years.

Mr. Brown is from Manchester, England, and is a graduate of Mechanical Engineering from Leicester Polytechnic, Leicester, England as well as a Certified Professional Engineer since 1988 and a member of the Institute of Corporate Directors since 2009.

Brian A. Felesky

Mr. Felesky is counsel at the law firm of Felesky Flynn LLP in Calgary, Alberta. He is a senior tax practitioner involved in structuring company reorganizations, acquisitions and spin-offs. He is also a member of the board of Precision Drilling Corporation, RS Technologies Inc., Cequence Energy Ltd. and various private corporations. He is a member of the audit committee of RS Technologies Inc. and chair of the audit committee of Cequence Energy Ltd. Mr. Felesky is actively involved in not-for-profit and charitable organizations. He is the co-chair of Homefront on Domestic Violence, a member of the senate of Athol Murray College of Notre Dame, board member of the Calgary Stampede Foundation, a Council member of the Alberta Order of Excellence, and a member of the Calgary Executive of the Institute of Corporate Directors.

Mr. Felesky is a Queen's Counsel and Member of the Order of Canada. He is a recipient of an honorary doctorate of Laws from the University of Calgary. He is a graduate of and holds the ICD.D certification from the Institute of Corporate Directors (ICD).

Allen R. Hagerman, FCA

Mr. Hagerman is currently Executive Vice President of Canadian Oil Sands Limited and prior to 2007 was Chief Financial Officer of Canadian Oil Sands Limited. Mr. Hagerman is a Director of Precision Drilling Corporation and the Calgary Exhibition and Stampede.

Mr. Hagerman received a Bachelor of Commerce degree from the University of Alberta, a Masters of Business Administration from the Harvard Business School and is a chartered accountant with a corporate finance qualification with the Canadian Institute of Chartered Accountants. He is a graduate of and holds the ICD.D certification from the ICD.

Mr. Hagerman is a Fellow of the Alberta Institute of Chartered Accountants, past Chair of the Alberta Children's Hospital Foundation and past President of the Financial Executives Institute, Calgary Chapter.

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Francois L. Poirier

Mr. Poirier had a 20 year career in management consulting and financial services, most recently as Managing Director and Group Head of Power Investment Banking for JP Morgan Securities in New York. He has advised on mergers and acquisitions, for both buyers and sellers; led leveraged buyouts; structured project financing; and issued common stock and convertible securities for companies in the energy sector. Mr. Poirier has also lectured on private equity at the Schulich School of Business, York University.

Mr. Poirier received a Bachelor of Operations Research from the University of Ottawa and a Masters of Business Administration from the Schulich School of Business at York University.

Mr. Poirier currently serves as Vice Chairman on the board of one not-for-profit entity, The North York Harvest Food Bank. He is a graduate of and holds the ICD.D certification from the ICD.

Rodney D. Wimer

Mr. Wimer is Managing Director of Mazama Capital Partners LLC (a private investment firm) and a limited partner of Fulcrum Power Services L.P (energy) since October 2002. Mr. Wimer was general partner of Fulcrum Energy LLC from October 2002 to September 2009 and director from October 2002 to December 2010. Prior thereto, he was President of the Commercial Power Division of Dynegy, Inc. from March 2001 until his retirement in January 2002.

Mr. Wimer is a graduate of the Stanford University Executive Program and attended the Advanced Management Program of Phillips Petroleum Company. He has an undergraduate degree in Earth Sciences from Eastern Washington University and completed post-graduate work in geography and earth sciences at Portland State University.

James Oosterbaan

Mr. Oosterbaan was Senior Vice President, Commercial Services of Capital Power Corporation until January 4, 2011, when he was appointed Senior Vice President, Operations & Commodity Portfolio Management of Capital Power Corporation. Prior thereto, he was Senior Vice President at EPCOR, responsible for the competitive power and water businesses in Alberta. Mr. Oosterbaan joined EPCOR in 2001. His areas of focus were business development, major project construction, commodity trading, water and power plant operations, and sales to end use customers. During his time at EPCOR, Mr. Oosterbaan was successful in guiding and further developing EPCOR's competitive water and power and commodity trading businesses through the deregulation of the Alberta electricity markets.

Prior to joining EPCOR, Mr. Oosterbaan was a consultant in the energy and information technology sectors, and employed with the Westcoast Energy Group of Companies. While at Westcoast, he had management responsibilities in the areas of marketing, business development, forecasting, natural gas supply portfolio management, and regulatory affairs.

Mr. Oosterbaan is a graduate of Stanford University's Executive Management Program. He holds a Master of Business Administration from the Ivey School of Business and a Bachelor of Business Administration (Honours) from Wilfred Laurier University.

Stuart A. Lee

Mr. Lee is Senior Vice President and Chief Financial Officer of Capital Power Corporation. He has led several equity and debt offerings to finance the Partnership's acquisitions. He joined EPCOR in 2003 as Vice President and Corporate Controller.

Mr. Lee is a chartered accountant who articled with one of the large international accounting firms. Prior to joining EPCOR, Mr. Lee worked for five years for Celanese Canada Inc., a large

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petrochemical manufacturer, as Vice-President and Controller where he was responsible for the reporting, treasury, tax, IT and supply chain functions for the Canadian operations. Mr. Lee has more than 23 years of relevant financial and reporting experience.

Officers(1)

Name, Province/State and Country of Residence, and Date became an Officer and Units held	Title	Principal Occupation During the Past Five Years
B. Kathryn Chisholm Alberta, Canada August 31, 2005 Units held: 1,316(2) Date of Birth: May, 1963	Senior Vice President, General Counsel and Corporate Secretary	Senior Vice President, General Counsel and Corporate Secretary of Capital Power Corporation from July 2009 to present; prior thereto, Senior Vice President, General Counsel and Corporate Secretary of EPCOR Utilities Inc. from May 2005; prior thereto, Associate General Counsel of EPCOR Utilities Inc. from September 2004.
Peter D. Johanson Alberta, Canada May 8, 2009 Units held: 400(2) Date of Birth: August, 1971	Controller	Controller of CPI Income Services Ltd. from July 2009 to present; prior thereto, Controller of EPCOR Power from November 2008; prior thereto, Senior Finance Manager of EPCOR Utilities Inc. from December 2006; prior thereto, Manager, Asset Valuation of EPCOR Utilities Inc. from April 2003.
John D. H. Patterson Alberta, Canada May 9, 2008 Units held: 2,353(2) Date of Birth: June, 1946	Vice President and Treasurer	Vice President and Treasurer, Capital Power Corporation from July 2009; prior thereto, Vice President and Treasurer, EPCOR Power Services Ltd., EPCOR Power L.P. and subsidiaries from April 2007 and Vice President and Treasurer, EPCOR Utilities Inc. and subsidiaries from November 2005; prior

		thereto, Assistant Treasurer, EPCOR Utilities Inc. and subsidiaries from January 2000.
Leah M. Fitzgerald Alberta, Canada July 9, 2009 Units held: <1(2) Date of Birth: August, 1967	Assistant Corporate Secretary	Associate General Counsel and Assistant Corporate Secretary of Capital Power Corporation from November 2010 to present; prior thereto, Director, Ethics and Assistant Corporate Secretary of Capital Power Corporation from July 2009 to November 2010; prior thereto, Chief Compliance Officer of EPCOR Utilities Inc. from October 2007; prior thereto, Associate Lawyer for Field LLP (law firm) from July 2006; prior thereto, Associate Lawyer for Brownlee LLP (law firm) from September 2002.
Anthony Scozzafava Alberta, Canada June 24, 2009 Units Held: 2,309(2) Date of Birth: February, 1967	Chief Financial Officer	Vice President, Taxation of Capital Power Corporation from July 2009 to present and Chief Financial Officer of the CPI Income Services Ltd. from June, 2009 to present; prior thereto, Vice President, Taxation of EPCOR Utilities Inc. from July 2001.

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Name, Province/State and Country of Residence, and Date became an Officer and Units held	Title	Principal Occupation During the Past Five Years
David Hermanson Illinois, U.S. Units Held: Nil(2) Date of Birth: August, 1957	Vice President, Operations of Capital Power U.S.A.(3)	Vice President, Operations of Capital Power U.S.A. from July 2009 to present; prior thereto Vice President Operations at EPCOR USA from May 2008; prior thereto General Manager at EPCOR USA from November 2006 to April 2008; General Manager of Primary Energy from January 2005 to October 2006.

(1) Stuart Lee, who is President of the Partnership, is included in the Directors table. Brian Vaasjo and Graham Brown are also included in the Directors table. Each of Messrs. Vaasjo, Lee and Brown performs a role as or similar to an executive officer of the Partnership.

(2) Represents as of December 31, 2010, the number of Units of the Partnership beneficially owned, or controlled or directed, directly or indirectly, by such persons.

(3) Mr. Hermanson performs a role as or similar to an executive officer of the Partnership.

As at December 31, 2010, the directors of the General Partner who are not also executive officers of the General Partner, as a group, beneficially owned, or controlled or directed, directly or indirectly, 27,373 Units ($17.95 per Unit as at the close of trading on December 31, 2010 for a value of $491,345) which is less than 1% of the issued and outstanding Units.

As at December 31, 2010, the directors and executive officers of the General Partner, as a group, beneficially owned, or controlled or directed, directly or indirectly, 37,335 Units ($17.95 per unit as at the close of trading on December 31, 2010 for a value of $670,163) which is less than 1% of the issued and outstanding Units.

Committees of the Board

Board of Directors / Governance Committee / Audit Committee / Independent Directors Committee

The governance of the Partnership is the responsibility of the Board and the rights, authority and limitations on the General Partner are described in the Partnership Agreement.

The Partnership is structured such that the role of the Chair and President of the General Partner are split between two individuals. The Chair, who is the President and Chief Executive Officer of Capital Power, has a casting vote or second vote in case of a tie vote at any meeting of the Board. In addition, the Board has appointed a Lead Director who is an independent director.

The Chair's prime responsibility is seeking to ensure the effective operation of the Board of Directors by managing Board and Unitholder meetings, monitoring and overseeing the strategic agenda of the Partnership, and providing leadership and advice respecting the General Partner's business planning processes and the Partnership's corporate governance.

The President of the General Partner provides day-to-day leadership and management to the General Partner and represents Management on the Board. The President's primary duties and objectives include: leading the General Partner; managing the Partnership's relationship with limited partners and the investment community; formulating strategies and plans and presenting them to the Board for approval; seeking to ensure that information management processes support the early identification of issues appropriately addressed by the Board; keeping the Board fully informed of the Partnership's progress toward achievement of its goals, objectives and policies in a timely and candid manner by managing the supporting material provided to the Board; leading the delivery of all functions provided for in the Management and Operations Agreements; leading the search for accretive

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transactions for presentation to the Board; and creating and maintaining the appropriate "tone at the top" to ensure that a "culture of integrity" applies to Capital Power's performance of functions pursuant to the Management and Operations Agreements.

The primary responsibilities of the Board's Lead Director are to seek to ensure that appropriate structures are in place so the Board can function independently of management, to lead the process by which the Independent Directors Committee seeks to ensure that the Board represents and protects the interests of all Unitholders, and to act as Chair of the Board when non-independent directors (including the Chair) are conflicted, such as when the Board is discussing or determining issues related to the Manager's compensation and when non-arm's length issues are negotiated between Capital Power and the Partnership. The Lead Director is required to be independent as such term is defined under applicable Canadian securities law. The Lead Director position is filled by Mr. Allen Hagerman.

The Board currently has four committees and one sub-committee:

- The Corporate Governance Committee (with a sub-committee comprising a Nominating Committee when required);
- The Independent Directors Committee;
- The Audit Committee;
- The Special Committee; and
- The Strategic Review Sub-Committee.

There is no executive committee or compensation committee (see "Compensation Discussion & Analysis").

Written position descriptions for the Chairman of the Board, the Chair of each Board committee, the Lead Director and President of the General Partner, are contained in the various Terms of Reference attached to this AIF.

The Terms of Reference for the Board of the General Partner are attached as Schedule B to this AIF.

Corporate Governance Committee

The Corporate Governance Committee (GC) is currently composed of Allen Hagerman, Brian Vaasjo and Rod Wimer (Chair). Both Mr. Hagerman and Mr. Wimer are independent as such term is defined under applicable Canadian securities law and mandated by the GC's terms of reference. See "Board of Directors and Executive Officers".

The GC operates under the Corporate Governance Committee Terms of Reference attached as Schedule C to this AIF.

In general, the GC is tasked to assist the Board in developing the Partnership's approach to corporate governance issues, including, the response to applicable corporate governance guidelines and standards set by regulators or stock exchanges on which the Partnership's Units are listed. The GC is also responsible for assessing the effectiveness of the Partnership's system of corporate governance and, where necessary, making recommendations for improvement of the Partnership's system of corporate governance to ensure high standards of governance are achieved and maintained. The mandate of the GC includes: (i) monitoring and assessing the relationship between the Board and management, defining limits of management's responsibilities and seeking to ensure that there is a process in place to enable the Board to function independently of management; (ii) developing terms of reference or position descriptions for the Board, the Lead Director, President and any senior officers of the Partnership where necessary; (iii) reviewing potential conflicts for directors; (iv) seeking to ensure the

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ongoing adequacy, integrity and implementation of the strategic planning process; (v) reviewing and recommending to the Board rules and guidelines governing and regulating the affairs of the Board such as indemnification and compensation of directors; (vi) reviewing with the Manager its relevant succession plans, training programs, compensation policies and officer appointments; (vii) preparing and reviewing results and reporting to the Board on an annual assessment of Board and committee performance, including an evaluation of the competencies and skills that the Board as a whole should possess, and the basis of the evaluation and making recommendations to improve Board and Committee effectiveness; and (viii) reviewing periodically the performance and contribution of individual Board members.

In addition, when required, the GC forms a sub-committee, composed entirely of Independent Directors, to serve as a Nominating Committee for the Board to assess potential candidates new for appointment as Independent Directors and make recommendations in respect thereof to the Board. Potential Independent Director candidates are assessed with a view to the critical skills they can bring to the Board and their alignment to the strategic plan of the Partnership. The GC, and ultimately the Board, undertakes a regular review of the current skills set of the Board as a whole to identify potential areas where a gap may exist and to anticipate new skills that may be required as the Partnership pursues its strategy. Subsequent to the Nominating Committee's recommendation of potential new candidates, the Board approves the slate of nominees for election which are presented for election annually by the shareholder of the General Partner.

The GC is also tasked with the preparation of and review of results and subsequent reporting to the Board on the annual assessment of Board and committee performance, including an evaluation of the competencies and skills that the Board as a whole should possess, and the basis of the evaluation and including a periodic review of the performance and contribution of individual Board members. To assist in this review, questionnaires relating to Board and committee assessments are provided to each director for completion and these are reviewed by the GC. The GC uses the information in this evaluation to report to the Board.

The GC also makes recommendations to improve Board and committee effectiveness. The GC undertakes a Board (including a peer review of individual members) and committee evaluation on an annual basis.

Audit Committee

The Audit Committee (AC) is currently composed of Brian Felesky (Chair), Allen Hagerman (Vice Chair) and Francois Poirier. The Board has determined that all members of the AC are independent and financially literate as such terms are defined under applicable Canadian securities law and mandated under the AC's terms of reference. See "Board of Directors and Executive Officers". The Board based these determinations regarding financial literacy on the education and breadth and depth of experience of each AC member. See "Board of Directors Directors" for a description of each member's relevant education and experience.

The AC is directly responsible for overseeing the work of the external auditor engaged for the purpose of reviewing or attesting services, including the resolution of disagreements between management and the external auditor regarding financial reporting.

The AC is responsible for assisting the Board in overseeing the integrity of the Partnership's financial statements, compliance with legal and regulatory requirements and ensuring the independence and performance of the Partnership's internal audit function and external auditors. The AC's Terms of Reference, are attached as Schedule D to this AIF.

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Independent Directors Committee

The Independent Directors Committee (IDC) is currently composed of Allen Hagerman (Chair/Lead Director), Brian Felesky, Francois Poirier and Rod Wimer. All IDC members are independent as such term is defined under applicable Canadian securities law and mandated under the IDC's terms of reference. See "Board of Directors and Executive Officers".

The IDC operates under the Independent Directors Committee Terms of Reference, attached as Schedule E to this AIF. The IDC is responsible for carrying out the obligations assigned to it by the Partnership Agreement, including reviewing, and, if thought appropriate, recommending for approval by the Board, all material transactions or agreements between the Partnership and Capital Power and its associates or affiliates.

The IDC meets whenever deemed appropriate and necessary by the Independent Directors, without the presence of non-independent directors or management and generally at the end of all regular meetings of the Board. The IDC met 10 times in 2010 in connection with these regular meetings.

Apart from their respective roles as directors of the General Partner, a description of the education and experience of Allen Hagerman (Chair/Lead Director), Brian Felesky, Francois Poirier and Rod Wimer, the members of the Independent Directors Committee, that is relevant to the performance of their responsibilities as independent directors and members of the Partnership's committees is found under "Board of Directors Directors".

Other Committees

The Partnership established two additional committees during 2010, the Special Committee and the Strategic Review Sub-Committee.

The Special Committee of the Independent Directors of the Partnership, consisting of Allen Hagerman, Brian Felesky, Francois Poirier (as chair) and Rod Wimer, was formed to review and consider on behalf of the Partnership potential alternatives for the restructuring of the relationship between Capital Power and the Partnership. The Special Committee met 20 times in 2010.

The Strategic Review Sub-Committee, consisting of Independent Director Francois Poirier and Stuart Lee, President of the General Partner and a senior officer of Capital Power, was created to act in an administrative capacity to the Board of Directors of the General Partner in the context of its strategic review process, and for that purpose, to lead the investigation of available strategic alternatives in the best interests of the Partnership.

The Special Committee and the Strategic Review Sub-Committee both have written Terms of Reference, which due to the ongoing, sensitive nature of the strategic review have not been included as schedules.

Director Orientation and Continuing Education

All Directors are provided with an orientation to the duties and obligations of directors and the business of the Partnership. Opportunities for meetings and discussions with senior management and other directors are also available and the details of the orientation of each new director are tailored to that Director's individual needs and areas of interest. In addition, a Corporate Governance Reference Manual (the CGR Manual) is provided to new Directors which helps familiarize new Directors with the Partnership (which is also updated, as appropriate and as necessary, for all existing Directors). The current CGR Manual covers a wide range of topics including: background information on the Partnership; information on Board structure; certain details on orientation and education; and key governance documents, policies, guidelines, codes and procedures. All Directors have participated with senior management at offsite strategic planning sessions at which all significant aspects of the Partnership's operations, opportunities and strategies are discussed. In addition the Board and the AC have attended a training session on International Financial Reporting Standards (IFRS) and the AC receives regular updates on the IFRS conversion projects.

In 2010, as part of their continuing education, the Directors were given an in-depth presentation on IFRS on November 22, 2010.

Management also periodically provides Directors with articles, papers and other materials relating to or addressing issues relevant to the Partnership, its business, and the various regulatory and legal regimes within which it operates, including on corporate governance matters. Directors are responsible for reviewing the materials provided and for generally keeping their knowledge of issues relevant to the Partnership current through the media and other public sources of information. The Partnership reimburses Directors for fifty percent of the cost of attending pre-approved educational conferences, industry symposia and other seminars (including direct out-of-pocket expenses related to travel) when in the Board's opinion, the Partnership will benefit from the Director's attendance at the seminar.

The Partnership provides Directors with the opportunity to tour each of the various types of facilities and plants owned by the Partnership on a periodic basis.

Ethics Policy

On April 27, 2010, the Partnership adopted a new Ethics Policy. Certification by all employees on the Ethics Policy was obtained in 2010. A copy of the Partnership's Ethics Policy can be obtained from the Partnership's website at www.capitalpowerincome.ca or under the Partnership's SEDAR profile at www.sedar.com. The Ethics Policy contemplates certification of all new personnel and periodic certification of existing personnel of the Manager and of the Independent Directors. The Manager has appointed an employee who is responsible for monitoring compliance with the Ethics Policy. Members of management are instructed to monitor compliance with the Ethics Policy and to report any compliance issues. The AC is mandated, to the extent it deems necessary or appropriate, to review and recommend to the Board for approval policy changes and program initiatives with respect to the implementation of the Ethics Policy and to obtain reports and report to the Board on the status and adequacy of the Partnership's efforts in seeking to ensure its businesses are conducted and its facilities are operated in an ethical, legally compliant and socially responsible manner, in accordance with the Ethics Policy.

External Auditor Service Fees

The table below sets out amounts billed by KPMG LLP in its capacity as the Partnership's external auditor. KPMG LLP did not provide or bill for any tax services or other services outside its audit and audit related services in 2010 and 2009.

Fee Category ($000's)	**2010**	**2009(1)**	**Description of Fee Category**
Audit Fees	$ 826	$ 694	Aggregate fees billed for audit services.
Audit Related Fees(1)	$ Nil	$ 57	Aggregate Partnership's fees billed by external auditor for the assurance and related services that are reasonably related to performance of the audit or review of the Partnership's financial statements and are not reported as Audit Fees.
All Other Fees(2)	$ Nil	$ Nil	
Total	**$ 826**	**$ 751**	

(1) 2009 figures have been restated to reflect fees on an accrual basis. Previously they were disclosed on a cash basis.

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(2) Audit Related Fees are for services provided on financial instruments and due diligence comfort provided in respect of the Partnership's annual and certain interim management's discussion and analysis in connection with a prospectus filing.

(3) All Other Fees are for services provided in respect of internal control over financial reporting and disclosure controls and procedures advisory matters.

Pre-Approval Policies and Procedures

The AC's Terms of Reference provides that all non-audit services to be provided by the external auditor for the Partnership or its subsidiaries require pre-approval by the AC. The AC can delegate this pre-approval function to one or more members of the AC, provided that any exercise of the delegated pre-approval function must be reported to the AC at the next committee meeting following the pre-approval.

COMPENSATION DISCUSSION AND ANALYSIS

The Partnership does not directly employ its executive officers. The General Partner has contracted for management and administrative services of the Partnership to be provided by the Manager. Accordingly, all of the executive officers of the General Partner serve in that capacity as nominees of the Manager in accordance with the Management and Operations Agreements and are therefore not compensated directly by the Partnership. The Manager, or its affiliates, employs substantially all of the staff carrying out the duties for the Partnership, including the Partnership's executive officers, in return for the payment of a fixed fee by the Partnership (the details of which are more particularly described herein under "Management of the Partnership" and "Interests of Management and Others in Material Transactions"). In addition, the Partnership pays incentive and other fees to the Manager that are based on the performance of the Partnership. See "Management of the Partnership" and "Interests of Management and Others in Material Transactions". The compensation paid to the General Partner's executive officers has no direct link to the fees paid to the Manager.

The performance of the Partnership is an important element of Capital Power's overall corporate financial performance. Approximately 30% of the Partnership's Funds From Operations (FFO) is included in determining Capital Power's overall corporate financial performance for purposes of the performance measures applied under Capital Power's corporate short-term incentive plan (STIP) for the period December 31, 2010. The Total Recordable Injury Frequency Rate performance measure includes all reportable incidents and exposure hours of the 18 facilities that Capital Power employees operate on behalf of the Partnership.

The General Partner is a direct wholly-owned subsidiary of CPI Investments. EPCOR owns all of the 51 voting, non-participating shares of CPI Investments and Capital Power owns all of the 49 voting, participating shares of CPI Investments. The Manager is controlled by Capital Power. Consequently, decisions relating to the compensation of the Partnership's executive officers are based on their respective roles, responsibilities and services within Capital Power as a whole and on Capital Power's overall performance relative to goals and targets established for Capital Power as a whole. Prior to July 2009, decisions relating to the compensation of the Partnership's executive officers were similarly based on their respective roles, responsibilities and services within EPCOR as a whole and on EPCOR's overall performance relative to goals and targets established for EPCOR as a whole.

Executive compensation disclosure in this AIF is provided in respect of the Named Executive Officers (NEOs) of the Partnership (as such term is defined in Form 51-102F6 Statement of Executive Compensation of the Canadian Securities Administrators, each of whom is employed and compensated by Capital Power). In accordance with Form 51-102F6, the NEOs include the President of the General Partner (as Chief Executive Officer), the Chief Financial Officer of the General Partner and each of the three most highly compensated other executive officers of the General Partner, or individuals acting

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in a similar capacity. The three most highly compensated executive officers of the General Partner, other than the President and the Chief Financial Officer, have been determined by multiplying the amount of each of Capital Power's executive officer's total compensation from Capital Power by the proportion of their respective time generally spent on matters pertaining directly to the Partnership. On this basis, the NEOs of the Partnership for 2010 were:

- Stuart Anthony Lee, President of the General Partner;
- Anthony Scozzafava, Chief Financial Officer of the General Partner;
- Brian Tellef Vaasjo, Chairman of the General Partner;
- Graham Lloyd Brown, Senior Vice President, Operations of Capital Power; and
- David Hermanson, Vice President, US Operations of Capital Power.

The NEOs' remuneration reported in the Summary Compensation Table and other tabular disclosure in this AIF represents the entire compensation paid to the Partnership's NEOs by Capital Power, (all compensation including salary, short-term and long-term incentives, pension and other benefits) based on their respective roles, responsibilities and services within Capital Power, as applicable, as a whole.

Capital Power Corporate Governance, Compensation & Nominating Committee

Composition

The Corporate Governance, Compensation & Nominating Committee (the Capital Power CGC&N Committee) of the Capital Power Board of Directors approves, or recommends for approval, all remuneration to be awarded through Capital Power's executive compensation program to the Partnership's NEOs who are executives of Capital Power, including annual base salary, short-term and long-term incentive and executive allowances. Remuneration for the Partnership's NEOs who are not executives of Capital Power is determined under Capital Power's management compensation programs over which the Capital Power CGC&N Committee has oversight.

The Capital Power CGC&N Committee is a committee of the Capital Power Board of Directors, composed of five members, each of whom, other than Mr. Cruickshank, is independent from Capital Power within the meaning of applicable Canadian securities laws. The members of the Capital Power CGC&N Committee are: Albrecht W.A. Bellstedt (Chair), Richard Cruickshank, Brian F. MacNeill, Robert Lawrence Phillips and Janice Rennie. As Chair of the Board, Don Lowry also attends Capital Power CGC&N Committee meetings in an ex-officio, non-voting capacity.

Mandate

With respect to executive compensation, the Capital Power CGC&N Committee assists the Capital Power Board of Directors in fulfilling its responsibilities relating to the compensation, evaluation and succession of directors and employees of Capital Power, including the Partnership's NEOs and provides oversight of the Company's corporate governance and identifying conditions for Board nomination. The role of the Capital Power CGC&N Committee with respect to compensation is to:

- Oversee, review and recommend for approval by the Capital Power Board of Directors, executive compensation policies including all forms of compensation for each member of the Capital Power's executive team, including the Partnership's NEOs;

Oversee the general compensation policies and plans for Capital Power; and

Review and approve the annual performance measures for incentive plans.

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The Capital Power CGC&N Committee has written Terms of Reference that establish its purpose, responsibilities, and membership.

The Capital Power CGC&N Committee follows an objective process for determining compensation by holding "in camera" sessions at the end of each committee meeting, without management present.

In November of 2010, the Capital Power CGC&N Committee engaged Hugessen Consulting to provide them with independent advice in respect of Capital Power directors' and executives' compensation and to advise the Capital Power CGC&N Committee, on a go-forward basis, on levels of compensation in the competitive market in which Capital Power operates and on other compensation matters.

In its role as independent compensation consultant to the Capital Power CGC&N Committee, Hugessen Consulting will:

- Keep the Committee members abreast of issues arising in the area of executive compensation;
- Provide comment on Capital Power compensation policy & strategy (including peer group utilized, pay mix, and positioning); and
- Represent the Capital Power Board of Directors/CGC&N Committee in interactions with major institutional shareholders regarding executive compensation issues and advise the Capital Power Board of Directors / CGC&N Committee on institutional shareholder issues, their associations and proxy advisors.

The Partnership does not engage Hugessen Consulting as an executive compensation consultant and therefore no amounts were paid by the Partnership to Hugessen Consulting for executive compensation advice.

Prior to that, Towers Watson acted as advisor to both Management and the Capital Power CGC&N Committee. The Partnership does not engage Towers Watson as an executive compensation consultant and therefore no amounts were paid by the Partnership to Towers Watson for executive compensation advice. Towers Watson continues to act as Management's consultant and will provide consulting advice and administrative support to Capital Power on compensation, pension and benefits matters.

Compensation Approval Process

In accordance with its Terms of Reference the Capital Power CGC&N Committee carries out its responsibilities on an on-going basis throughout the year and has established a review process which includes the following matters:

- An annual review of compensation strategy and design, to ensure that they continue to meet the needs of the business of Capital Power. The Capital Power CGC&N Committee also reviews on an annual basis the total compensation of Capital Power executives including the Partnership's NEOs against market compensation data and recommends the approval of any changes to compensation levels to the Capital Power Board of Directors; In instances where the NEO is not also an executive of Capital Power, changes to compensation levels are subject to Capital Power's annual salary review process and approved by Capital Power's Chief Executive Officer;
- The Capital Power CGC&N Committee approves the overall salary budget of Capital Power for the year, and the annual incentive-plan design;
- The Capital Power CGC&N Committee presented for informational purposes with the Chief Executive Officer of Capital Power's evaluation of the individual performance of the other executives of Capital Power including the Partnership's NEOs;

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- The Capital Power CGC&N Committee reviews and recommends to the Capital Power Board of Directors for approval the payout amounts for executives of Capital Power (including the Partnership's NEOs) under the Capital Power corporate short-term incentive plan and reviews and approves the aggregate payout amount of the Capital Power corporate short-term incentive plan to all employees of Capital Power; and

- The Capital Power CGC&N Committee reviews and approves the long-term incentive measures in place to ensure that they reinforce the key priorities of the business of Capital Power.

Compensation Philosophy and Objectives

The Partnership's NEOs participate in the same direct compensation (salary, short and long term incentives), pension and benefit programs of Capital Power as other similarly positioned Capital Power Executives and management. The compensation of Capital Power's executives including the Partnership's NEOs, is influenced by a number of factors, including business strategy, organizational performance and governance. Capital Power's compensation philosophy aims to achieve the following objectives:

- Attract and retain high performing employees through market competitive compensation and a performance culture that rewards superior performance;

- Link compensation with Capital Power's business strategy and objectives; and

- Align total compensation with the interests of shareholders.

These objectives have guided the development of a compensation model that includes base salary, short-term and long-term incentives. The compensation programs are designed to be market competitive with organizations in the Canadian energy and utility industries that are of a similar size and scope of operations to those of Capital Power. For executives, the primary focus is on performance related compensation (short-term and long-term incentives). For the Partnership's NEOs that are not executives of Capital Power, base salary may be more important. Capital Power's short-term incentive plan (STIP) is designed to reward executives for achievement of corporate and individual goals that have a one-year time horizon. Capital Power's long-term incentive plan (LTIP) is designed to align longer-term executive and stakeholder interests by focusing executives on Capital Power's longer-term strategic objectives and sustained value creation.

In March 2011, the Capital Power CGC&N Committee approved a revised compensation philosophy, for executive positions where base salaries and short-term and long-term incentive opportunities will be targeted at the median of the market. The aggregate of base salary, short-term and long-term incentives will produce median compensation in the event of target performance of Capital Power and/or the individual, above median compensation in the event of superior performance of Capital Power and/or individual and below median compensation if performance falls short of expectations. This approach will better align Capital Power's executive compensation practices with those of their comparator companies. The performance of the Partnership is an important element of Capital Power's overall financial performance.

Prior to this, Capital Power was targeting base salaries at below the median and short and long-term incentive opportunities at above the median of this market in order to encourage an entrepreneurial spirit on start-up.

Comparator Group

For 2010 Capital Power's executive comparator group consisted of companies that met the following criteria:

- Autonomous, publicly-traded Canadian companies;

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Primarily Alberta-based companies;

Classified in the Energy and Utilities industries; and

Revenue between $1 billion and $30 billion.

As the 2010 comparator group was comprised of companies within a wide revenue range and included significantly larger organizations the data used to assess the competitiveness of executive compensation was size-adjusted to Capital Power's revenue using single-regression analysis.

In 2010, the executive compensation comparator group comprised the following companies:

ATCO Ltd.	Nexen Inc.
Canadian Natural Resources Ltd.	Spectra Energy Corp.
Emera Inc.	Suncor Energy Inc.
Enbridge Inc.	Talisman Energy Inc.
Ensign Energy Services Inc.	TransAlta Corp.
Fortis Inc.	TransCanada Corp.
Husky Energy Inc.	

For 2011 the comparator group selection criteria will be refined by narrowing the revenue scope to companies with revenues between $750 million and $10 billion. Raw percentile statistics for compensation data will be used, as opposed to regressed market data. Similar compensation levels are observed when market data from the 2010 comparator group is regressed to the market median revenue of the 2011 comparator group. Further refinements will be considered for 2012.

For 2011 the executive compensation comparator group will comprise the following companies, with which Capital Power competes for talent and which the Capital Power CGC&N Committee believes to be an appropriate comparator group:

ATCO Ltd.	Pengrowth Energy Corp.
ARC Resources Ltd.	Penn West Energy Corp.
Emera Inc.	ShawCor Ltd.
Fortis Inc	Talisman Energy Inc.
Nexen Inc.	TransAlta Corp.
Pembina Pipeline Corp.	TransCanada Corp.

Third party compensation surveys are used to compare base salary, short-term incentive and long-term incentive levels of Capital Power's executives to those of its comparators. Based on the analysis, compensation recommendations are formulated and brought forth to the Capital Power CGC&N Committee.

A broader comparator group is used to benchmark senior management and professional positions.

It should be noted that since the Partnership's NEOs' compensation is set based on their roles and responsibilities within Capital Power, the comparator group companies represent peers of Capital Power and are not chosen based on a comparison to the Partnership itself.

Total Compensation Elements and Objectives

The following table outlines the key elements of Capital Power's compensation program, including the objective and rationale for each compensation element and what each compensation element is intended to reward.

Compensation Element	Objective and Rationale	What the Element Rewards
Base salary	To provide a competitive base level of fixed compensation based on responsibilities, scope and market data.	Experience, expertise, knowledge and scope of responsibilities.
Short-term incentive program	To provide a component of compensation that is conditional on performance and rewards the achievement of annual targets that support Capital Power's strategic direction.	Achievement of short-term company objectives and/or individual performance goals.
Long-term incentive program	To provide a component of compensation that is conditional on sustained mid-term to long-term performance and aligns the interests of the executive officer with the interests of the shareholder through holdings of significant equity interests and to aid in long-term retention of executive officers.	Achievement of mid-term to long-term performance results resulting in share price increases.
Other compensation arrangements (and perquisites)	To provide a competitive total compensation package.	Scope of responsibilities.
Pension and other retirement benefits	To provide a competitive total compensation package that includes market competitive health benefits and retirement savings vehicles. Facilitates long-term financial security for executive officers and aids in retention.	Tenure.

Overview of Compensation Mix for NEOs in 2010

The table below outlines the mix of base salary and compensation-at-risk for each of the Partnership's NEOs. The percentages shown for short and long-term incentive compensation assume achievement of target Capital Power performance levels. While variable compensation represents the greatest proportion of total compensation for several of the partnership's NEOs, the actual mix varies

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according to the NEO's role and level in Capital Power, their relative ability to influence short and long-term business results of Capital Power and market practices for comparable positions.

Executive	Base Salary	Short-Term Incentive Compensation	Long-Term Incentive Compensation
Stuart Anthony Lee	45%	23%	32%
Anthony Scozzafava	66%	17%	17%
Brian Tellef Vaasjo	33%	25%	42%
Graham Lloyd Brown	47%	24%	29%
David Hermanson	65%	19%	16%

Base Salary

The Partnership does not have an annual base salary program for executive officers. The Partnership's NEOs are compensated under the Capital Power base salary program. Salaries are determined based on the responsibilities of each position, the executive's experience, expertise and knowledge when compared with market, individual performance and internal comparability and will generally align at a point below the median of the comparator group for executive positions with similar responsibilities to those of Capital Power. Base salaries for non-executive positions with Capital Power are targeted at the median of the comparator group for positions with similar responsibilities to those of Capital Power.

Short-Term Incentive Compensation

The Partnership does not have a short-term incentive program (STIP) for executive officers. The Partnership's NEOs are compensated under Capital Power's corporate STIP.

The Corporate Short-Term Incentive Plan

Capital Power believes that the corporate STIP should provide competitive bonuses that reflect corporate and individual performance. Corporate measures focus on corporate results and create joint accountability among the executives. Individual performance objectives allow for the differentiation of payouts based on individual contributions.

In 2010, the Capital Power CGC&N Committee approved a new STIP. Performance measures and targets were chosen to better reflect Capital Power's business objectives and to improve the line of sight for all employees through better alignment to the financial reporting documentation and other activities considered critical for success.

Performance Measures

Performance measures are approved by the Capital Power CGC&N Committee through the annual budgeting process based on Capital Power Corporation's performance. The only extent to which the compensation of the Capital Power executives who act as officers of the General Partner is affected by the Partnership's performance is to the extent that Capital Power Corporation performance measures incorporate the performance of the Partnership. At the end of the year, actual performance is measured against these pre-determined performance measures and the STIP pays out on the basis of achievement, within an expected range of performance: a minimum performance expectation (threshold), an expected result (target) and a plan maximum (stretch). The maximum payout under the plan will not exceed 2.0 times target. The following table shows Capital Power's performance measures applied for the period from January 1, 2010 to December 31, 2010 for the purposes of the STIP awards there under for the executive group.

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Performance Measure	Weight	Target	Actual Result	Performance Assessment
Financial				
Funds from Operations(1)	70%	$250.0 million	$259.0 million	Above Target
Aggregated Safety				
Total Recordable Injury Frequency Rate (TRIF)(2)	15%	1.20	1.48	Below Target
People Measure				
Organizational Design(3)	5%	Complete the final two phases of the organizational design project. Incorporate accountabilities and deliverables into the individual performance measures for the CEO and SVPs.	Completed the final two phases of the organizational design project. Incorporated accountabilities and deliverables into the individual performance measures for the CEO, SVPs, Directors and Senior Managers.	Above Target
Succession Planning(4)	5%	Complete executive level succession plans. Create a developmental plan for each high potential employee.	Completed executive and director level succession plans. Created a developmental plan for each high potential employee.	Above Target
Turnover(5)	5%	6.0%	6.0%	At Target

Notes:

(1) The performance measure "Funds from Operations" represents cash provided by operating activities (GAAP defined term) less changes in operating working capital. Includes approximately 30.0% of the Partnership's funds from operations.

(2) The performance measure "Total Recordable Injury Frequency Rate" represents the total number of employee fatalities and injuries resulting in lost time, restricted work duties or medical treatment per 200,000 work hours.

(3) The performance measure "Organizational Design" represents the completion of an organizational design project which includes the final two phases, determining cross-functional accountabilities and authorities; and, aligning business deliverables to each stratum.

(4) The performance measure "Succession Planning" represents the process for identifying and developing internal people with the potential to fill Senior Vice President and Director positions.

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(5)
The performance measure "Turnover" represents the number of permanent full-time employees who voluntarily leave the Partnership in 2010 divided by the actual number of active permanent full-time employees on December 31, 2009.

Individual performance measures for the executive group include a combination of quantitative and qualitative goals with no pre-determined weightings. These goals are intended to align with the annual corporate objectives and reflect goals which have a reasonable likelihood of being achieved within the relevant year. If the goals are met, this would be considered target performance for purposes of the plan. Individual performance is rated on a scale from 1 to 5, with 1 being Unacceptable and 5 being Outstanding.

2010 STIP Targets

The following table outlines the target incentive opportunity for each of the Partnership's NEOs for the fiscal year ended December 31, 2010:

Name	Minimum	Target	Maximum
Stuart Anthony Lee	0%	50%	100%
Anthony Scozzafava	0%	25%	50%
Brian Tellef Vaasjo	0%	75%	150%
Graham Lloyd Brown	0%	50%	100%
David Hermanson	0%	30%	60%

2010 STIP Payout Formula

The target incentive opportunity for each position is a percentage of base salary and will generally align at a point above the median of the comparator group for executive positions with similar responsibilities to those of Capital Power.

Payouts are based on the weighted-average of the combined corporate performance measures adjusted for individual performance results. The following formula is used to determine the final STIP award:

Base Salary	×	**Annual Incentive Target Payout**	×	**Corporate Performance Result / Individual Performance Modifier**	=	**Annual STIP Award**
(e.g. $300,000)		(e.g. 50% of salary = $150,000)		(e.g. 150%)		(e.g. $225,000)

The individual performance modifier is determined based on the following matrix and will be calculated using linear interpolation when corporate performance results fall between the threshold and target or target and stretch. The illustration above is based on "stretch" corporate performance results and an individual performance rating of "3".

	Individual Performance Rating				
Corporate Performance Result	**1**	**2**	**3**	**4**	**5**
Stretch	0%	75%	150%	175%	200%
Target	0%	50%	100%	125%	150%
Threshold	0%	0%	50%	75%	100%
Below Threshold	0%	0%	0%	0%	0%

Capital Power CGC&N Committee Oversight

After considering and evaluating the performance results for the year, the Capital Power CGC&N Committee retains the discretion to adjust payouts under Capital Power short-term incentive plans to

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take into account factors affecting performance that are beyond the participants' control resulting in an outcome that would be unfair by either "over or underpaying" incentive or creating unintentional results.

Long-Term Incentive Compensation

The Partnership does not have a long-term incentive program (LTIP) for executive officers. The Partnership's NEOs are compensated under Capital Power's LTIP. Capital Power has two LTIPs for its executives and employees, including the Partnership's NEOs; a LTIP for 2009 (the 2009 Plan) and a LTIP for the 2010 fiscal year and onward (the LTI Plan). The issuance of Units is not included as part of the LTIP due to the potential for a conflict of interest due to the Partnership's relationship with Capital Power. See "Business Risks Conflict of interest risk related to the Partnership's relationship with Capital Power Corporation" in the MD&A.

The 2009 Plan

The 2009 Plan is structured as a stock option plan providing for one-time only grants of options that replaced the value of outstanding 2006, 2007, 2008 and 2009 EPCOR phantom option grants held by individuals who became employees and executives of Capital Power. An aggregate of 2,183,100 stock options were granted to eligible participants of Capital Power including to individuals acting as officers of the Partnership on July 8, 2009. No further grants will be made under the 2009 Plan.

Options granted under the 2009 Plan may be exercised, once vested, up to the expiry date of July 8 2016. The 2009 Plan also provides that, unless otherwise determined by the Capital Power Board of Directors, options will terminate within specified time periods set out in the 2009 Plan following the termination of employment of an eligible participant with the Company or affiliated entities. The options granted under the 2009 Plan were unvested at grant, with one third vesting on January 1 of each of 2010, 2011, and 2012.

When used in this paragraph, the terms "insiders" and "security based compensation arrangement" have the meanings ascribed thereto in the TSX rules for this purpose. The number of Common Shares that may be (a) reserved for issuance to insiders pursuant to the 2009 Plan and under any other security based compensation arrangement of Capital Power and (b) issued within a one-year period to insiders pursuant to the 2009 Plan and under any other security based compensation arrangement of Capital Power, is in each case limited to 10% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units of Capital Power L.P.. The number of Common Shares which may be reserved for issuance to any one participant pursuant to the 2009 Plan and under any other security based compensation arrangement of Capital Power or options for services granted by Capital Power is limited to 5% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units of Capital Power L.P.

If options granted under the 2009 Plan would otherwise expire during a trading black-out period or within 10 business days of the end of such period, the expiry date of the options will be extended to the tenth business day following the end of the black-out period.

The interests of any participant under the 2009 Plan or in any option are not transferable, except to a spouse, minor child or grandchild or a trust or corporation controlled by the participant of which any combination of the participant and the foregoing are shareholders or beneficiaries. Upon any such permitted transfer, the transferred options shall be deemed for the purposes of the 2009 Plan to continue to be held by the participant. Upon death, the participant's legal personal representative shall receive the benefit of the option.

The 2009 Plan may be amended with the approval of the Capital Power Board of Directors, in accordance with TSX requirements and, to the extent provided under the 2009 Plan, the approval of

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shareholders of Capital Power. The Capital Power Board of Directors has overall authority for interpreting, applying, amending and terminating the 2009 Plan.

The LTI Plan

Under the LTI Plan, the Capital Power Corporation Board of Directors may in its discretion grant from time to time Capital Power stock options, performance share units (PSUs), restricted share units (RSUs) and stock appreciation rights (SARs) to employees and consultants, the "eligible participants", of Capital Power and its affiliated entities. An aggregate of 1,246,046 stock options and 152,801 PSUs were granted to eligible participants of Capital Power including to individuals acting as officers of the Partnership under the LTI Plan on March 9, 2010.

Eligibility to receive grants of Capital Power stock options, PSUs, RSUs and SARs and grant guidelines are determined by the Capital Power Board of Directors, provided that non-employee directors of Capital Power are not eligible to participate in the LTI Plan. The CEO of Capital Power recommends to the Capital Power CGC&N Committee the actual recipients of such grants from among the eligible participants, the composition of the grants (as among options, PSUs, RSUs and SARs) and the actual grant size, taking into consideration such factors as their levels of responsibility, performance and market information. In determining the size and composition of the grants that the Capital Power CGC&N Committee recommends to the Capital Power Board of Directors, the Capital Power CGC&N Committee will consider their expected payout and the competitiveness of Capital Power's total compensation relative to Capital Power's comparator group in addition to the recommendation of Capital Power's CEO. The Capital Power CGC&N Committee will determine the grant size and composition to be recommended to the Capital Power Board of Directors in respect of the CEO of Capital Power. Capital Power intends to make new grants under the LTI Plan in subsequent years without taking prior grants into account when making such new grants.

An aggregate of five million Capital Power Common Shares or approximately 6.4% of the number of outstanding Common Shares, after giving effect to the exchange of the Exchangeable LP Units of Capital Power L.P., have been reserved for issuance from treasury under the LTI Plan and the 2009 Plan. Capital Power may satisfy its obligations to deliver Common Shares under the LTI Plan by the issuance of Common Shares from treasury or by acquiring Common Shares in the market.

When used in this paragraph, the terms "insiders" and "security based compensation arrangement" have the meanings ascribed thereto in the TSX rules for this purpose. The number of Common Shares that may be (a) reserved for issuance to insiders pursuant to the LTI Plan and under any other security based compensation arrangement of Capital Power and (b) issued within a one-year period to insiders pursuant to the LTI Plan and under any other security based compensation arrangement of Capital Power, is in each case limited to 10% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units of Capital Power L.P.. The number of Common Shares which may be reserved for issuance to any one participant pursuant to the LTI Plan and under any other security based compensation arrangement of Capital Power or options or rights granted for services granted by Capital Power is limited to 5% of the total number of outstanding Common Shares after giving effect to the exchange of the Exchangeable LP Units of Capital Power L.P..

Options granted under the LTI Plan may be exercised during the period determined under the LTI Plan, which is generally seven years, or the shorter option period established by the Capital Power CGC&N Committee for any individual grant. The LTI Plan also provides that, unless otherwise determined by the Capital Power Board of Directors, options will terminate within specified time periods following the termination of employment of an eligible participant with the Company or affiliated entities. The exercise price for options granted under the LTI Plan is the closing price for Common Shares on the day prior to the grant. The exercise of options may, in the discretion of the Capital Power Board of Directors, be subject to vesting conditions, including specific time schedules for

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vesting and performance based conditions such as share price and financial results. The options granted on March 9, 2010 under the LTI Plan were unvested at grant, with one third vesting on March 9 of each of 2011, 2012 and 2013.

Under the LTI Plan, the Capital Power Board of Directors also has the discretion to attach a SAR to an option when granted to an eligible participant or at a later date. Such SARs provide the holder with a right to receive an amount in cash or Common Shares equal to the difference between the option exercise price at the time of the grant and the closing price for a Common Share on the last trading day prior to exercise. The exercise of any such SARs will be subject to the same terms and conditions as the options to which they are attached. When SARs attached to an option are exercised, the related options are cancelled and the Common Shares underlying such cancelled options will, to the extent not used to satisfy stock settled SARs, no longer be available for issuance under the LTI Plan.

The LTI Plan also permits eligible participants to receive grants of SARs that are not attached to options (Stand Alone SARs). Each Stand Alone SAR gives holders the right to receive an amount in cash or Common Shares equal to the difference between the market price of a Common Share at the time of grant and the market price of Common Shares at the time of exercise of the Stand Alone SAR. The "market price" used for this purpose is the simple average closing price of the Common Shares as traded on the stock exchange on which the highest aggregate volume of Common Shares have traded on each of the five trading days immediately preceding the grant or exercise date, as the case may be. Such amounts may also be payable at the election of the Company by the delivery of Common Shares. The exercise of Stand Alone SARs may also, at the discretion of the Capital Power Board of Directors, be subject to conditions similar to those that may be imposed on the exercise of stock options.

Under the LTI Plan, eligible participants may be granted PSUs or RSUs, which represent the right to receive an equivalent number of Common Shares at a specified release date or an amount equal to the market price of such number of Common Shares on the release date (market price having the same meaning as in the case of Stand Alone SARs). The delivery of such Common Shares or payment of cash in respect of PSUs or RSUs may, at the discretion of the Capital Power Board of Directors, be subject to vesting requirements similar to those described above with respect to the exercisability of options and SARs, including such time or performance based conditions as may be established by the Capital Power Board of Directors. The PSUs granted on March 9, 2010 under the LTI Plan vest on January 1, 2013. Payout is based on relative total shareholder return over a three-year performance period.

If incentives granted under the LTI Plan that are to be settled in newly issued Common Shares would otherwise expire during a trading black-out period or within 10 business days of the end of such period, the expiry date of the incentive will be extended to the tenth business day following the end of the black-out period.

The interests of any participant under the LTI Plan or in any option, PSUs, RSUs or SAR are not transferable, subject to limited exceptions. An option may be transferred to a spouse, minor child or grandchild or a trust corporation controlled by the participant of which any combination of the participant and the foregoing are shareholders or beneficiaries. Upon any such permitted transfer, the transferred options shall be deemed for the purposes of the 2009 Plan to continue to be held by the participant. Upon death, the participant's legal personal representative shall receive the benefit of the option.

The LTI Plan may be amended with the approval of the Capital Power Board of Directors, in accordance with TSX requirements and, to the extent provided under the LTI Plan, the approval of shareholders of Capital Power.

The Capital Power Board of Directors has overall authority for interpreting, applying, amending and terminating the LTI Plan.

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Benefit and Pension Plans

The Partnership does not have benefit or pension plans for executive officers. The Partnership's NEOs participate in Capital Power's benefit and pension plans. Capital Power's benefit and pension plans support the well-being of employees and facilitate retirement savings. The plans are reviewed periodically to determine whether they are competitive and whether they continue to meet Capital Power's business and human resources objectives.

Health and Welfare Benefits

The benefit plans are designed to protect the health of employees and their dependents, and cover them in the event of death or disability. The Partnership's NEOs participate in the same benefits program as all other permanent employees of Capital Power. Capital Power provides Canadian based executives with an executive benefit allowance, paid on a semi-monthly basis, to offset employee costs under the plan.

Executive Business Allowance

Executive officers of Capital Power, including the Partnership's NEOs, are provided with an annual taxable allowance that can be used to offset the cost of a variety of business related expenses including but not limited to memberships and other out-of-pocket expenses associated with performing the duties of the position.

Financial Planning Allowance

Mr. Vaasjo is eligible to receive an annual financial planning allowance from Capital Power in an amount not exceeding $5,000. Other NEOs, who are also executives of Capital Power, are eligible to receive an annual financial planning allowance in an amount not to exceed $3,500.

Capital Accumulation Plan

Under the voluntary Capital Accumulation Plan, all Canadian based non-bargaining unit employees of Capital Power may contribute up to 10% of their base salary towards a range of investment options, including Partnership Units. Employee contributions are matched to a maximum of 3% of base salary.

Pension Programs

Canadian based employees participate in one of two registered pension plans: the Local Authorities Pension Plan (LAPP) and the Capital Power Pension Plan. The Capital Power Pension Plan includes a defined contribution component and, for certain employees who work in the Partnership's plants, a defined benefit component. There are no NEOs of the Partnership who participate in the defined benefit component of the Capital Power Pension Plan. In addition, Canadian management employees whose benefits under the Capital Power Pension Plan or the LAPP are limited due to the Tax Act maximum pension or contribution limits are eligible to participate in the Capital Power sponsored Supplemental Pension Plan.

US based employees participate in the Capital Power 401(k) plan.

LAPP Plan

The LAPP is a contributory, defined benefit, best average earnings pension plan that is governed by the Public Sector Pension Plans Act (Alberta). The LAPP is a multi-employer pension plan that covers approximately 140,000 active members as at December 31, 2010 who are employed by Alberta municipalities, hospitals and other public entities. Mr. Lee, Mr. Scozzafava and Mr. Vaasjo participate in the LAPP.

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Benefits payable under the LAPP are based on the average of the best five consecutive years of pensionable earnings and years of service. Pensionable earnings are equal to base salary plus actual bonus, up to a maximum of 20% of base salary (effective January 1, 2004). Pensionable earnings are limited for each year of service after 1991 to the earnings which provide the maximum annual accrual under the Tax Act.

Subject to Tax Act limits, the benefit formula under the LAPP is 1.4% of the average of the best five consecutive year's annual pensionable earnings up to the average Year's Maximum Pensionable Earnings (YMPE) under the Canada Pension Plan plus 2% of the average of the best five consecutive year's annual pensionable earnings in excess of the five year average YMPE. The benefit formula is multiplied by years of service up to a maximum of 35 years.

Employee and employer contribution rates under the LAPP are set out in the plan rules and are adjusted from time to time by the LAPP Board of Trustees based on recommendations from the plan's actuary. In 2010, members were required to contribute 8.06% up to the YMPE plus 11.53% of pensionable earnings in excess of the YMPE, and employers contributed 9.06% up to the YMPE and 12.53% of pensionable earnings in excess of the YMPE.

The pension payable under the LAPP is reduced by 3% for each year that the combination of the individual's age and years of service is less than 85 or for each year the individual is younger than 65, whichever provides the lower reduction. No pension is payable if a participant has not completed two years of service.

The pension payable is indexed annually to 60% of the increase in the Alberta consumer price index.

The Capital Power Defined Contribution (DC) Plan

Contributions to the Capital Power DC Plan are made based on pensionable earnings subject to the annual limits imposed under the Tax Act. Specifically, members are required to contribute 5% of pensionable earnings and Capital Power contributes either 5%, 6.5%, or 8% of pensionable earnings depending on the member's length of service.

Mr. Brown participates in the Capital Power DC Plan.

In late 2010, the Capital Power DC Plan was amended to allow executive members the option to suspend their membership. Executive members who elect to suspend their membership will not receive any company contributions and cannot make employee contributions to the Capital Power DC Plan for the duration of the suspension. Executive members have the right to lift the suspension and thereby resume making employee contributions, at which point the company contributions will resume, for future service only from the date that the suspension is lifted. In addition, executive members have the option to elect to irrevocably transfer their account balance in the Capital Power Plan to a locked-in retirement savings vehicle.

Should an executive member choose to suspend their membership in the Capital Power DC Plan, Capital Power will provide a payment to the executive member equivalent to the amount that would have been paid into the executive member's plan had he or she not chosen to suspend their membership in the pension plan. Any such payment does not become part of the executive's base salary and is subject to all applicable taxes and payroll withholding requirements.

Supplemental Pension Plan (SPP)

Capital Power has established a non-registered, unfunded and non-contributory SPP that provides benefits that cannot be provided under the Capital Power registered pension plan or, if applicable, the LAPP due to the Tax Act maximum pension or contribution limits.

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All of the partnership's NEOs, with the exception of Mr. Hermanson, participate in the SPP.

The pensionable earnings defined under the SPP includes base salary and target bonus. For employees who transferred from EPCOR in July of 2009, the Capital Power SPP has the same provisions as the EPCOR Utilities Inc. Supplemental Pension Plan. Specifically, the SPP provides a defined benefit pension equal to 2% of the average pensionable earnings in excess of an earnings threshold multiplied by service after January 1, 2000. The SPP has the same early retirement and indexing provisions as the LAPP. For new hires after July 2009 the Capital Power SPP provides benefits on a defined contribution basis that are in excess of the Tax Act maximum contribution limits. For employees who transferred from EPCOR, Capital Power assumed all obligations from EPCOR relating to the entitlements accrued under the EPCOR Utilities Inc. Supplemental Pension Plan.

Executives who elect to withdraw from the Company DC Pension Plan are still eligible to participate in the SPP for earnings above the Tax Act maximum pension or contribution limits.

The Capital Power 401(k) Plan

Capital Power's US based employees including Mr. Hermanson participate in the Capital Power 401(k) Plan.

Members are permitted to make pre-tax elective contributions of up to 100% (less applicable tax withholdings) of eligible compensation (maximum of US$22,000 in 2009, including up to $5,500 in catch-up contributions for employees at least age 50). After tax contributions are not permitted. Eligible compensation includes total salary and wages during the plan year as reported on the W-2, including pre-tax contributions to the Plan. Annual compensation in excess of US$245,000, as adjusted for cost of living increases, is not included.

Capital Power matches employee contributions equal to 100% of the member's pre-tax contributions up to 5% of compensation plus Capital Power has the option to make additional matching contribution equal to 2% of the first 2% the member elects to defer. Each year Capital Power had the option to make an additional matching contribution and/or additional employer contribution on behalf of each eligible participant in amounts determined by Capital Power.

Interest credited on 401(k) accounts reflects the rate of return on investment options selected by the participant.

Mr. Brown participated in the Capital Power 401(k) from January 1, 2006 to December 31, 2009 and commenced participation in the Capital Power DC Plan on January 1, 2010.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table provides a summary of compensation for each of the Partnership's NEOs for the years ended December 31, 2010, 2009 and 2008. The NEOs' remuneration reported in the Summary Compensation Table represents the entire compensation paid to the Partnership's NEOs by Capital Power or EPCOR, as applicable, (all compensation including salary, short-term and long-term incentives, pension and other benefits) based on their respective roles, responsibilities and services within Capital Power or EPCOR, as applicable, as a whole.

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Name and Principal Position	Year	Salary(1)(7) ($)	Share Based Awards(2)(7) ($)	Option Based Awards(3)(7) ($)	Non-Equity Incentive Plan Compensation: Annual Incentive Plans(4)(7) ($)	Non-Equity Incentive Plan Compensation: Long-Term Incentive Plans(5)(7) ($)	Pension Value(6)(7) ($)	All Other Compensation(7) ($)	Total Compensation(7) ($)
Stuart Anthony Lee	2010	$ 338,269	$ 112,000	$ 112,000	$ 226,474	$ 0	$ 90,672	$ 43,309(18)	$ 922,725
President of the General	2009	$ 276,385		$ 152,144	$ 290,000	$ 0	$ 161,902	$ 95,165(19)	$ 975,596
Partner(8)(10)(11)	2008	$ 235,231		$ 0	$ 136,000	$ 4,427	$ 51,573	$ 31,822(20)	$ 459,053
Anthony Scozzafava									
	2010	$ 253,364	$ 30,726	$ 30,726	$ 101,772	$ 0	$ 45,591	$ 10,000	$ 472,180
Chief Financial Officer of	2009	$ 243,892		$ 95,604	$ 106,552	$ 0	$ 37,663	$ 9,438	$ 493,149
the General Partner(8)(11)	2008	$ 234,177		$ 0	$ 97,000	$ 931	$ 51,678	$ 8,333	$ 392,119
Brian Tellef Vaasjo									
	2010	$ 679,231	$ 406,250	$ 406,250	$ 679,000	$ 0	$ 246,466	$ 56,042(21)	$ 2,473,240
Chairman of the General	2009	$ 529,923		$ 610,632	$ 843,000	$ 0	$ 788,003	$ 113,936(22)	$ 2,885,494
Partner(9)(10)(11)	2008	$ 422,692		$ 0	$ 341,000	$ 6,042	$ 122,903	$ 42,822(23)	$ 935,459
Graham Lloyd Brown									
	2010	$ 259,615	$ 74,999	$ 74,999	$ 137,500(17)	$ 0	$ 47,728	$ 39,398(24)	$ 634,240
SVP, Operations of Capital	2009	$ 277,699		$ 156,770	$ 204,414	$ 0	$ 19,585	$ 75,532(25)	$ 734,000
Power(9)(10)(11)(13)(14)(15)	2008	$ 228,435		$ 0	$ 199,342	$ 0	$ 12,259	$ 10,660(26)	$ 450,696
David Hermanson									
	2010	$ 218,530	$ 25,750	$ 25,750	$ 63,886	$ 0	$ 13,237	$ 729	$ 347,883
VP, US Operations of Capital	2009	$ 246,909		$ 79,670	$ 104,862	$ 0	$ 9,528	$ 19,938	$ 460,907
Power(9)(12)(14)(15)(16)	2008	$ 213,200		$ 0	$ 63,960	$ 0	$ 7,950	$ 0	$ 285,110

Notes:

(1) See "Compensation Discussion and Analysis Base Salary".

(2) 2010 share based awards represent the grant date expected value of the Capital Power PSU grant for 2010 under the LTI Plan. Payout is based on how the Capital Power's total shareholder return performs relative to the total shareholder return of the companies in the Capital Power performance peer group.

(3) 2010 option based awards represent the expected value of the Capital Power stock option grant for 2010 under the LTI Plan. 2009 option based awards represent the expected value of the Capital Power stock option grant for 2009 as well as the replacement for the outstanding 2006, 2007 and 2008 EPCOR grants under the 2009 Plan.

(4) See "Compensation Discussion and Analysis Short-Term Incentive Compensation". Represents short-term incentive award earned for the stated year's performance and paid in the subsequent year.

(5) See "Compensation Discussion and Analysis Long-Term Compensation". For 2008, reflects long-term incentive payment for the 4-year performance cycle from 2005 to 2008 and paid by EPCOR in 2009.

(6) See "Compensation Discussion and Analysis Benefit and Pension Plans". 2009 values reflect a one time increase in pensionable earnings as a result of the transfer of the NEOs from EPCOR to Capital Power.

(7) Represents the total annual salary, share-based awards, option-based awards, annual incentive compensation, long-term incentive compensation, annual compensatory pension value or other annual compensation value, as applicable, paid to the Partnership's NEOs by Capital Power, or EPCOR, as applicable.

(8) Mr. Lee and Mr. Scozzafava are designated NEOs based upon their respective positions as President and Chief Financial Officer of the General Partner.

(9) The approximate percentages of time that the NEOs spent rendering services to the Partnership relative to their services to Capital Power or EPCOR, as applicable, were as follows: Mr. Vaasjo 20% in 2010, 15% in 2009, 35% in 2008; Mr. Brown 60% in 2010, 75% in 2009, 95% in 2008; Mr. Hermanson 90% in both 2010 and 2009, 100% in 2008. A change in the percentage of time a NEO allocates to the Partnership would not affect the NEOs' compensation from Capital Power.

(10) NEOs who are directors of the General Partner do not and did not receive any incremental income from Capital Power or EPCOR or the Partnership for their roles as directors of the General Partner.

(11) Canadian based NEOs. See "Compensation Discussion and Analysis Benefit and Pension Plans".

(12) US based NEOs. See "Compensation Discussion and Analysis Benefit and Pension Plans".

(13) Mr. Brown retired from Capital Power in January 2011.

(14) For 2008, converted to Canadian dollars using an average conversion rate of 1.066 Canadian/US with the average rate based on 252 days of data provided by the Bank of Canada.

(15) For 2009, converted to Canadian dollars using an average conversion rate of 1.142 Canadian/US with the average rate based on 251 days of data provided by the Bank of Canada.

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(16) For 2010, converted to Canadian dollars using an average conversion rate of 1.030 Canadian/US with the average rate based on 251 days of data provided by the Bank of Canada.

(17) Mr. Brown's STIP award was paid out at target following his retirement.

(18) Includes an executive benefit allowance of $14,000 and an executive business allowance of $15,000.

(19) Includes a vacation payout of $56,385.

(20) Includes an executive benefit allowance of $13,404, an executive business allowance of $9,981 and a matching contribution into the EPCOR savings plan of $7,507.

(21) Includes an executive benefit allowance of $15,474, an executive business allowance of $15,000 and employer contributions to the Capital Power capital accumulation plan of $20,377.

(22) Includes a vacation payout of $64,866.

(23) Includes an executive benefit allowance of $13,790, an executive business allowance of $14,971 and a matching contribution into the EPCOR savings plan of $12,681.

(24) Includes an executive benefit allowance of $13,462 and an executive business allowance of $14,423.

(25) Includes a relocation allowance of $47,582 and an executive business allowance of $27,122.

(26) Includes an executive business allowance of $10,660.

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Long-Term Incentive Plan

The 2010 grant under the LTI Plan consisted of Stock Options and Performance Share Units, with 50% of the target value coming from each vehicle.

Options granted in 2010 vest in equal amounts on March 9 in each of 2011, 2012 and 2013 and have a seven-year term.

PSUs granted in 2010 vest on January 1, 2013 based on Capital Power's total shareholder return (share price plus dividend equivalents) relative to the total shareholder return of the companies in a performance peer group. Relative TSR was selected as the performance measure as it complements the absolute performance focus of stock options and is a holistic measure that encompasses share price performance plus dividends. Upon vesting, PSUs will be settled in cash.

The performance peer group consists of organizations with similar business characteristics (e.g., power generation/transmission/utility companies, high dividend yield), reflects companies that compete directly for capital with Capital Power and are consistent with the executive compensation comparator group. The composition of Capital Power's performance peer group will be reviewed annually by third party consultants and the Capital Power CGC&N Committee for continued relevance. In 2010, the performance peer group comprised the following companies:

Algonquin Power & Utilities Corp.	Enbridge Inc.
Atlantic Power Corp.	Fortis Inc.
Brookfield Renewable Power Inc.	Northland Power Inc.
Canadian Utilities Ltd.	TransAlta Corp.
Emera Inc.	TransCanada Corp.

A vesting range with a floor of 50% of target for minimum performance and a cap of 150% of target for maximum performance was established as Capital Power does not have a lengthy trading history and felt a conservative approach was appropriate. Accordingly;

50% of PSUs granted will vest if Capital Power's TSR is at or below the 25th percentile of its performance peer group;

100% of PSUs granted will vest if Capital Power's TSR is at the median of its performance peer group; and

150% of PSUs granted will vest if Capital Power's TSR is at or above the 75th percentile of its performance peer group.

Vesting is interpolated on a straight-line basis between threshold and target and between target and maximum.

The performance criteria and vesting range will be reviewed in 2013 for continued relevance.

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The following table sets forth the information regarding the options and PSUs that were granted to the Partnership's NEOs under the LTI Plan during the fiscal year ended December 31, 2010:

	Option-based Awards				Share-based Awards	
Name	**Number of securities underlying unexercised options (#)**	**Option exercise price ($)**	**Option expiration date(1)**	**Value of unexercised in-the-money options(2) ($)**	**Number of shares or units that have not vested(3) (#)**	**Market or payment value of share-based awards that have not vested(4) ($)**
Stuart Anthony Lee	47,160	22.50	March 9, 2017	$ 54,234	6,024	$ 142,465
Anthony Scozzafava	12,938	22.50	March 9, 2017	$ 14,879	1,653	$ 39,096
Brian Tellef Vaasjo	171,060	22.50	March 9, 2017	$ 196,719	21,850	$ 516,746
Graham Lloyd Brown	31,580	22.50	March 9, 2017&n			