

{ CAPITAL POWER INVESTOR MEETINGS

A photograph of a large industrial power plant with two tall smokestacks, situated behind a body of water and a lush green wetland area. The sky is a mix of blue and orange, suggesting dawn or dusk. In the foreground, there is a field of tall grass.

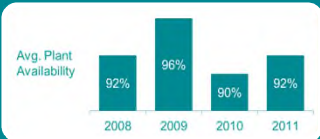
Brian Vaasjo, President & CEO
Stuart Lee, SVP & CFO
May, 2012

Capital Power overview



Growth-oriented independent power producer (IPP)

- Trading on the TSX (CPX); ~\$2.3B market cap (diluted); EV ~\$3.8B
- Spin-off of power generation assets from EPCOR/IPO in mid-2009



High quality generation portfolio

- Young and modern fleet with generation capacity of ~3,300 MW
- Generation from a combination of natural gas, coal, wind, and potentially solar
- Proven operating and construction history
- 4-year average plant availability of ~93%



Straight forward business model

- Stable and growing cash flow from a balanced portfolio of long-term contracts and merchant components, supported by an investment grade credit rating
- Focused on target markets in Western Canada (primarily Alberta), Ontario, US Southwest, US Northeast, and Mid-Atlantic US



Financial strength and strong cash flow generation

- BBB investment grade credit rating from S&P and DBRS
- 7.2% CAGR of cash flow per share from 2009-2011
- Attractive dividend yield of ~5%



Strong exposure to attractive Alberta power market

- Positive leverage to Alberta power market
- 53% of total owned capacity is in Alberta power market (~1,800 MW)

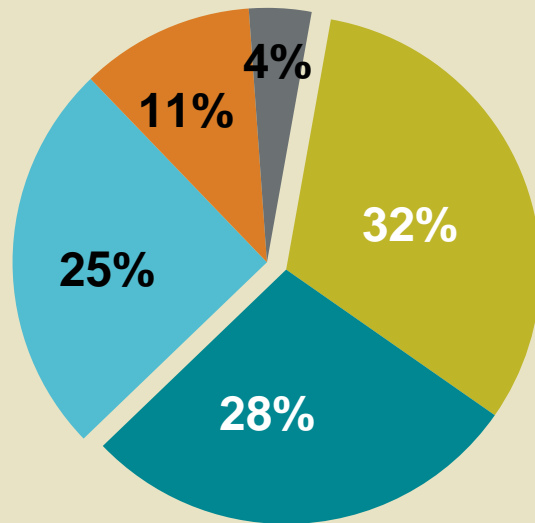
Balanced portfolio of merchant and contracted generation⁽¹⁾

Continue to have strong exposure to attractive Alberta power market

Today - 2012

15 facilities (3,351 MW)

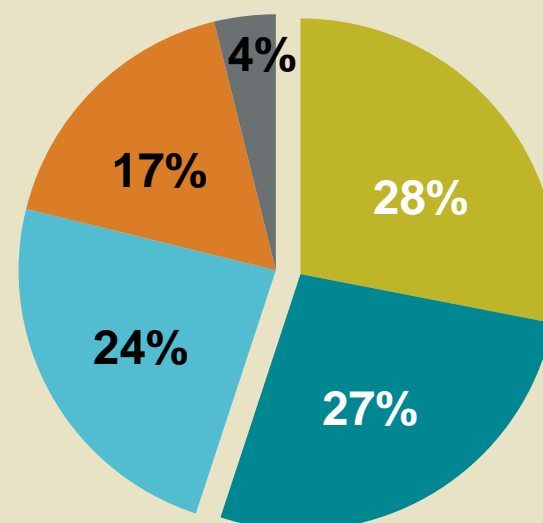
- 40% capacity contracted



Year-end 2014E

17 facilities (3,798 MW⁽²⁾)

- 45% capacity contracted



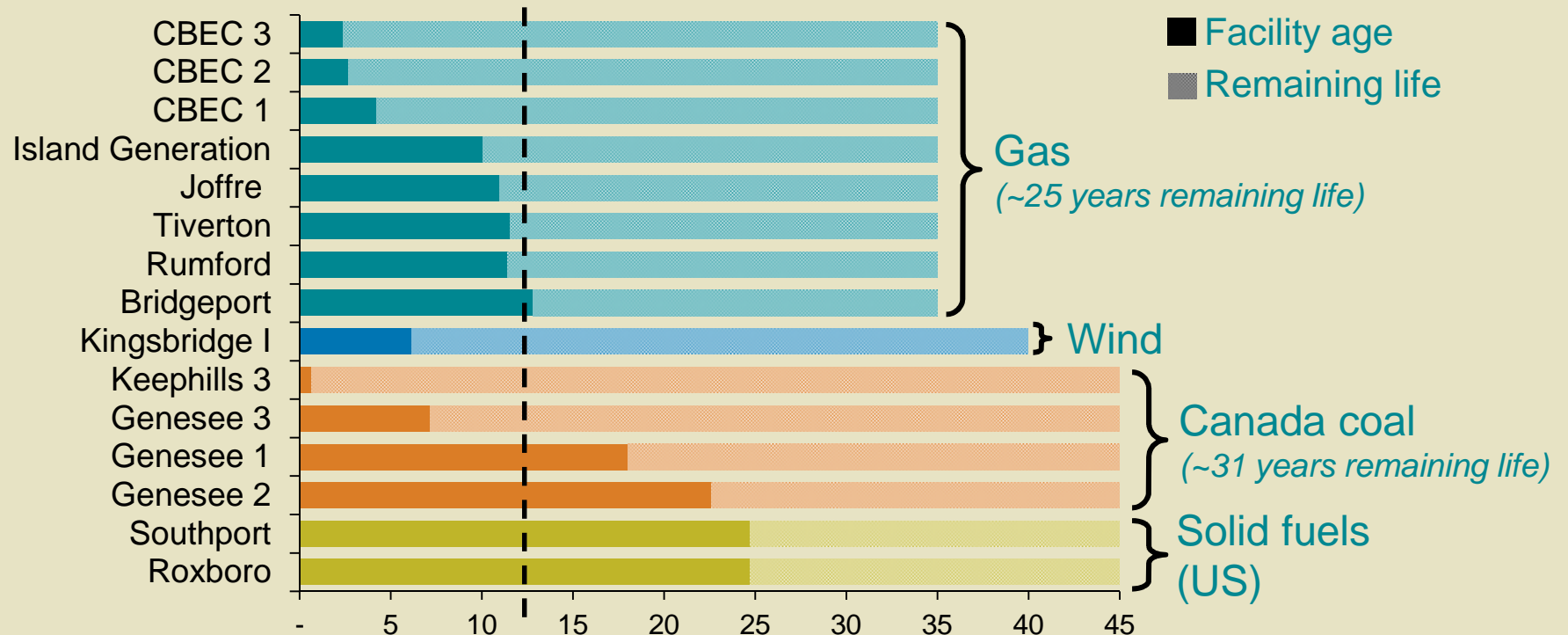
■ AB commercial ■ US Northeast commercial ■ Mid-Atlantic contracted
■ AB contracted ■ ON / BC contracted

(1) Based on MW owned capacity; excludes Sundance PPA (371 MW) and Clover Bar Landfill Gas (4.8 MW).

(2) Based on existing plants plus committed development projects and assuming divestiture of small hydro facilities.

Modern fleet

- Average weighted facility age of the current fleet is 12.5 years⁽¹⁾
- 4 new wind projects (487 MW) begin commercial operations in 2012 - 2014



- ~31 years remaining life on Canadian coal facilities
- Favorable coal air emissions being developed

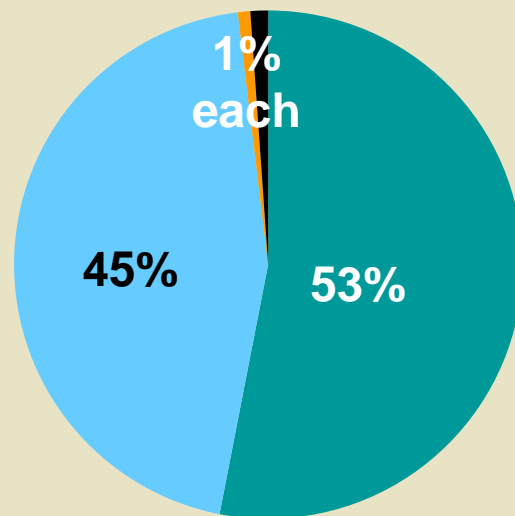
(1) Average facility age and remaining life weighted by owned capacity as of May 1/12 - based on existing assets and assuming divestiture of hydro facilities.

Technology focus⁽¹⁾

CPC's operations and growth are focused on four fuel sources: natural gas, coal, wind and solar

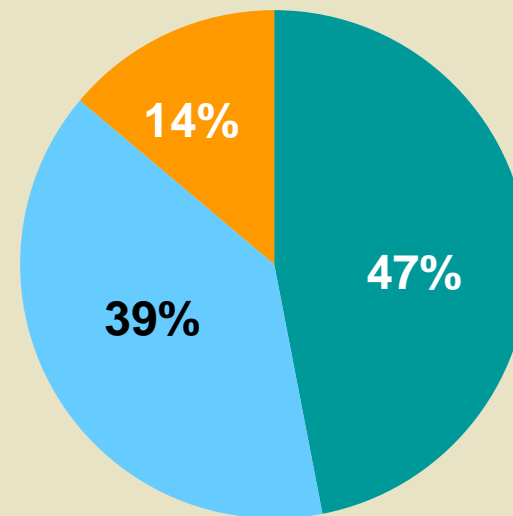
Current

15 facilities (3,351 MW)



By 2014 year-end

17 facilities (3,798 MW⁽²⁾)



■ Gas ■ Wind ■ Hydro ■ Coal & solid fuels

- Projects in development will increase owned wind capacity to 14% by 2014
- Expect to divest two remaining small hydro plants (40 MW total) by mid-2012

(1) Based on MW owned capacity; excludes Sundance PPA (371 MW) and Clover Bar Landfill Gas (4.8 MW).

(2) Based on existing plants plus committed development projects and assuming divestiture of small hydro facilities.

Favorable GHG emission regulations for coal-fired plants

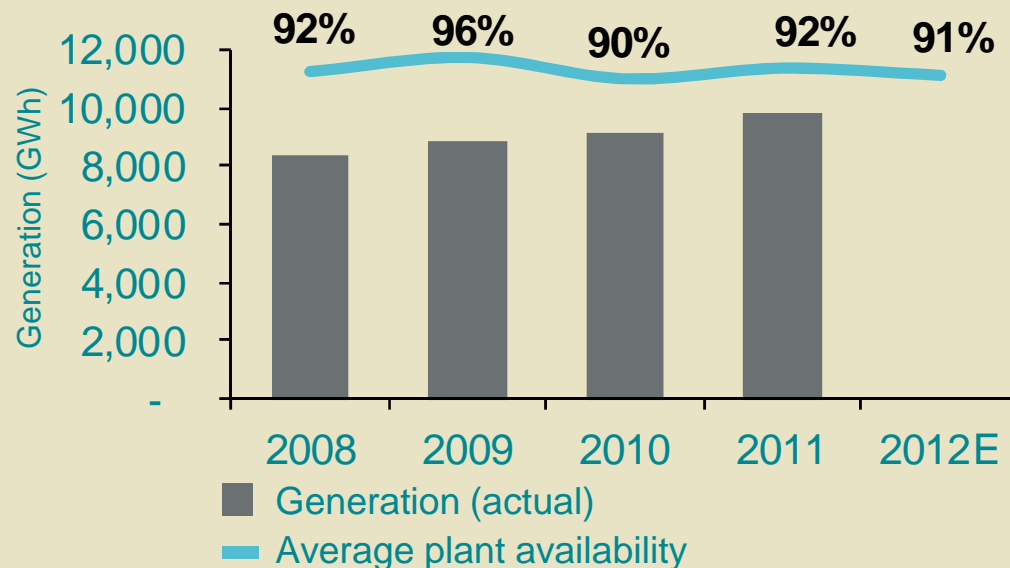
- Government of Canada's proposed plan (published in Q3/11) would apply a new greenhouse gases (GHG) emissions performance standard to new coal-fired electricity generation units
- New performance standard is intended to represent the intensity level of natural gas combined cycle technology
- Economic life expected to be set at the later of 45 years from COD or to the end of the unit's PPA
 - Other timeframes are also being discussed
- Proposed regulations are expected to have little if any impact on the Genesee units and Keephills 3 as the units are already commissioned and the useful lives of these units extends over several decades
 - ~31 years remaining life on Capital Power's coal facilities⁽¹⁾
 - Keephills 3 (COD Sep/11) and Genesee 3 are two of the most advanced coal-fired plants ever built in Canada

(1) Average remaining life weighted by owned capacity as of May 1/12.

Proven operating excellence

Capital Power has maintained high operating availability over a growing fleet and production volumes

Operating performance



- 4-year average plant availability of ~93%
- Q1/12 plant availability of 97%
- Canadian Electricity Association President's Award of Excellence for top-quartile safety performance⁽¹⁾

(1) Awarded Oct/11.

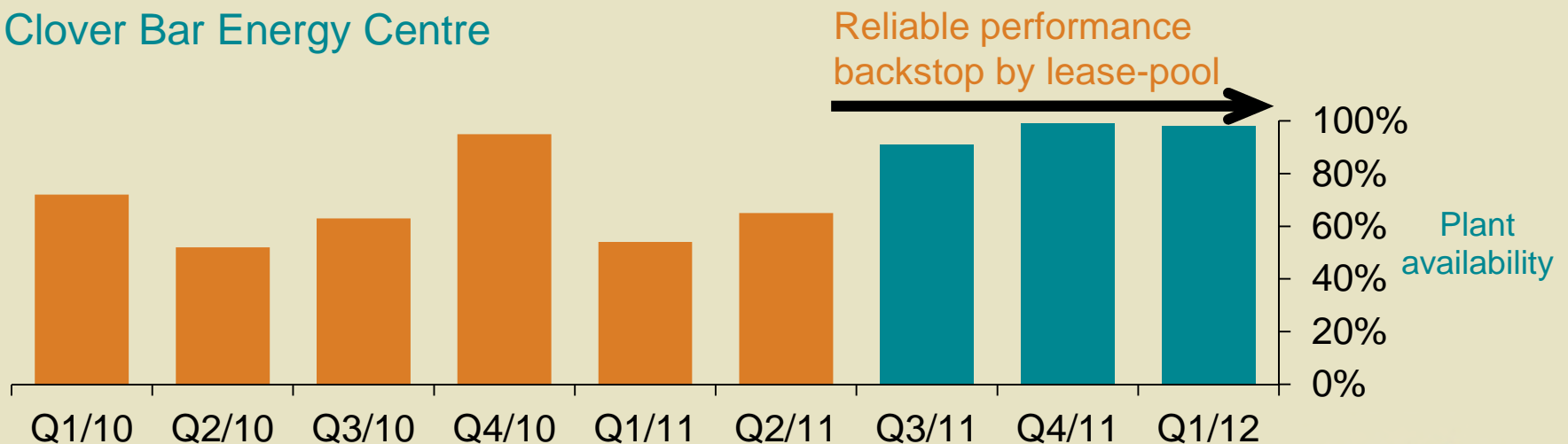


Enhanced reliability at Clover Bar

Participation in GE lease-pool minimizes outage periods and provides prudent risk management

- LMS 100 units can be replaced by a leased unit from GE in 2 - 4 days
- Clover Bar (243 MW) provides significant ability to manage our portfolio
 - Can power up to full load in 10 minutes, providing flexibility to respond to sudden changes in price and manage overall portfolio
 - Provides upside on power price increases
 - Protects downside on plant outages; successfully deployed in Q4/11 to backstop outage at Genesee 3

Clover Bar Energy Centre



North American footprint & target markets

Ownership interest in 15 facilities with more than 3,300 MW

Western Canada

- 53% of total owned capacity is in attractive AB power market
- 2 wind projects expected COD Q4/12

Ontario

- Target market for contracted assets
- 2 wind projects expected COD in 2013 and 2014

US Southwest

- Target market for contracted assets
- Solar and natural gas peaking opportunities

US Northeast

- 3 natural gas plants totaling 1,069 MW
- Form foundation for networked hub
- Efficient, young assets

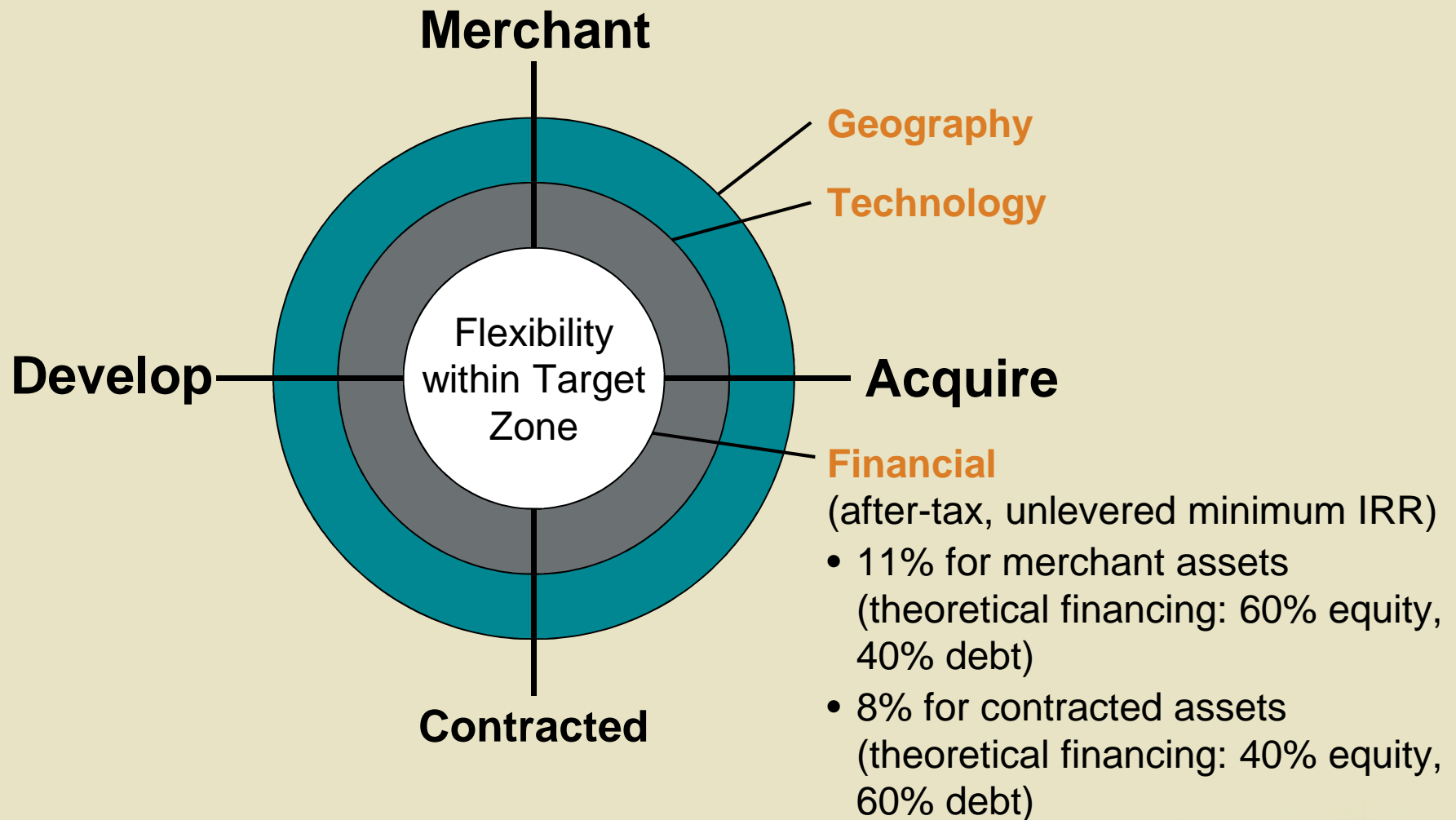
Mid-Atlantic US

- Solid fuel assets with 10-year PPAs

■ Plants in operation ■ Plants under construction or development

Framework for disciplined growth

Capital Power's strategy drives opportunity evaluation



Creating value through disciplined growth

Wind developments expected to be significantly accretive

- Significant experience in the construction and operation of both thermal (coal, natural gas) and renewable (wind, biomass, small hydro) facilities
- Four wind projects under development are expected to add ~\$0.15/share on an earnings and cash flow basis during the first two years of operations, with associated EBITDA of \$150M - \$160M
- Halkirk and Quality Wind projects expected COD in Q4/12

Halkirk Wind project

- 150 MW wind project near Halkirk, AB
- \$357M budget (inc. acquisition costs)
- Hybrid of contracted cash flows (20-year California Renewable Energy Credits (RECs) provide ~40% revenue) and merchant upside
- Unique wind regime in the AB market
- Readily accessible to transmission lines

Quality Wind project

- 142 MW wind farm near Tumbler Ridge B.C.
- \$455M development cost
- 100% contracted with a 25-year PPA with BC Hydro

2013 - 2014 Projects under development



K2 Wind Ontario

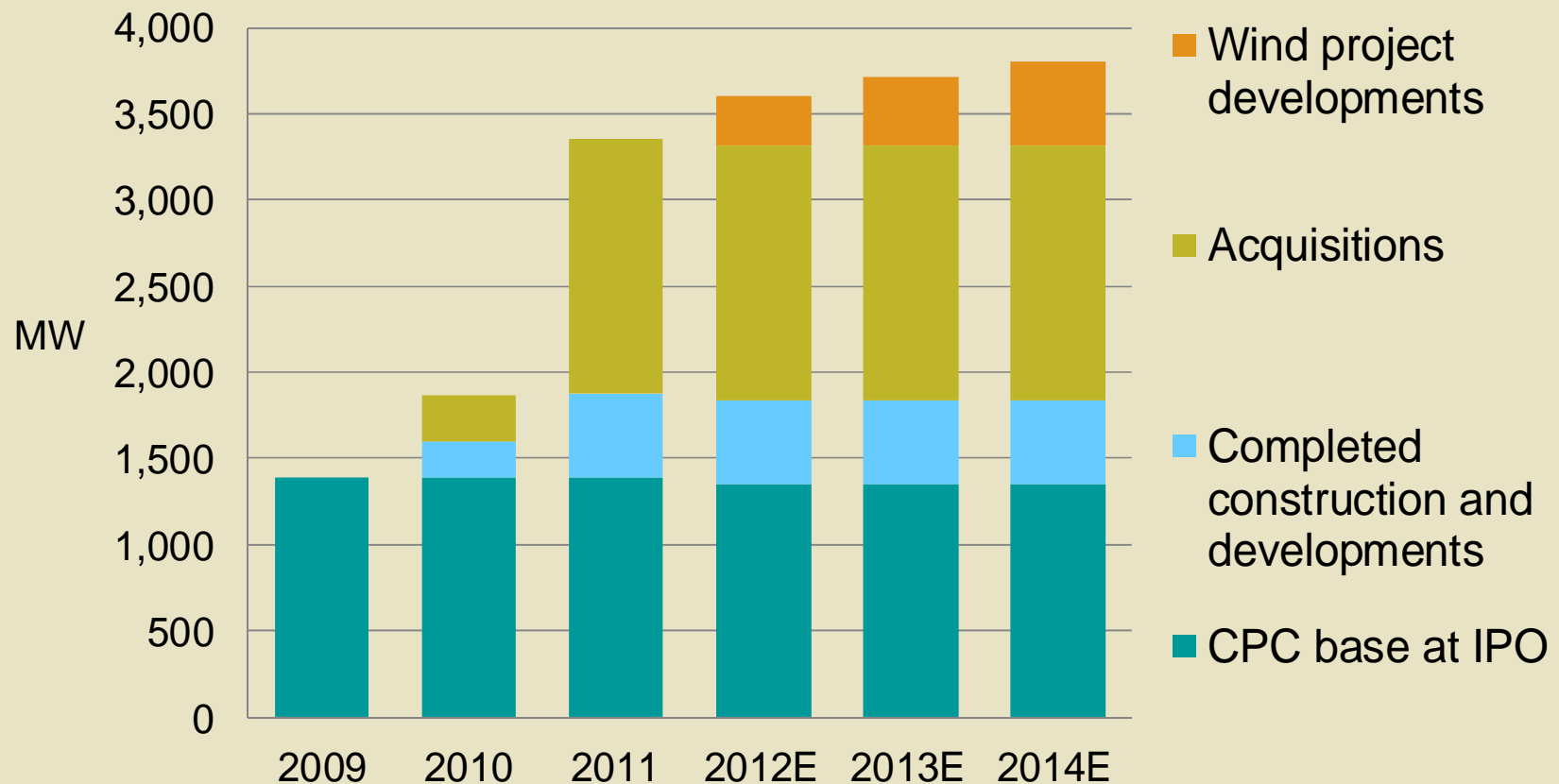
- 270 MW wind project in the township of Ashfield-Colborne-Wawanosh, ON
- Limited partnership between Capital Power, Samsung and Pattern
- Each partner will have an equal economic interest (33.3%) in the project
- Expected total project capex of \$874M; CPC's expected project capex is \$46M
- Contracted with a 20-year PPA with Ontario Power Authority for \$135/MWh

Port Dover & Nanticoke

- 105 MW wind farm in an area that covers the counties of Norfolk and Haldimand, ON
- \$340M development cost
- Contracted with a 20-year PPA with Ontario Power Authority for \$135/MWh

Capital Power's growth⁽¹⁾

487 MW of committed projects will increase contracted cash flows in 2012-2014



(1) Based on MW capacity owned plus committed projects minus expected divestitures.

Alberta power market

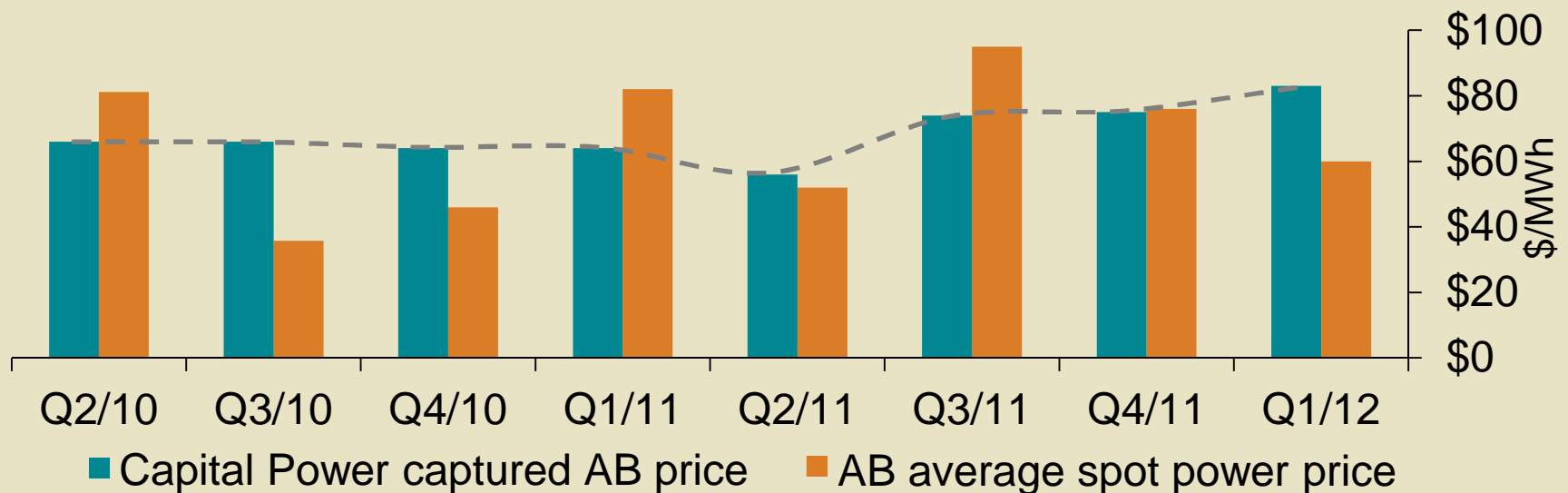
- Alberta (AB) has a competitive wholesale energy and ancillary services market operated by the Alberta Electric System Operator (AESO); market has an installed generation capacity of ~13,000 MW
- No capacity market – power generators must recover all costs through revenue earned in AB's energy and ancillary services market
- Entire province is a single zone where power prices are determined by the bid price of the incremental power generator (i.e. one with the highest cost of generation) that is dispatched to balance demand and supply in real-time
- AB's economy expected to grow above national average rate due to the impact of continued oil sands development activities that is a fundamental driver to increasing power demand
- AESO forecasts long-term energy and demand to grow at a rate of 3.1% annually until 2022⁽¹⁾
- AB government reviewing market design to look at reducing power price volatility for Regulated Rate Option customers
 - Do not expect any fundamental market design changes

(1) "2011 Annual Market Statistics and AESO 2012 Long-term Outlook", April 3/12, http://www.aeso.ca/downloads/2012LTO_Stakeholder_Presentation.pdf

Capturing upside from AB power prices

- Hedging positions based primarily on generation from Genesee 3 and Keephills 3 baseload coal plants and output from the Sundance PPA
- Actively trading (portfolio optimization) throughout various time periods to minimize portfolio risks and create incremental value

CPX's average realized power price has exceeded spot power prices by ~\$2.50/MWh over the past 2 years through forward contract sales and power trading activities



AB commercial portfolio positions

- Alberta portfolio hedged positions for AB baseload plants and Sundance PPA (% sold forward)

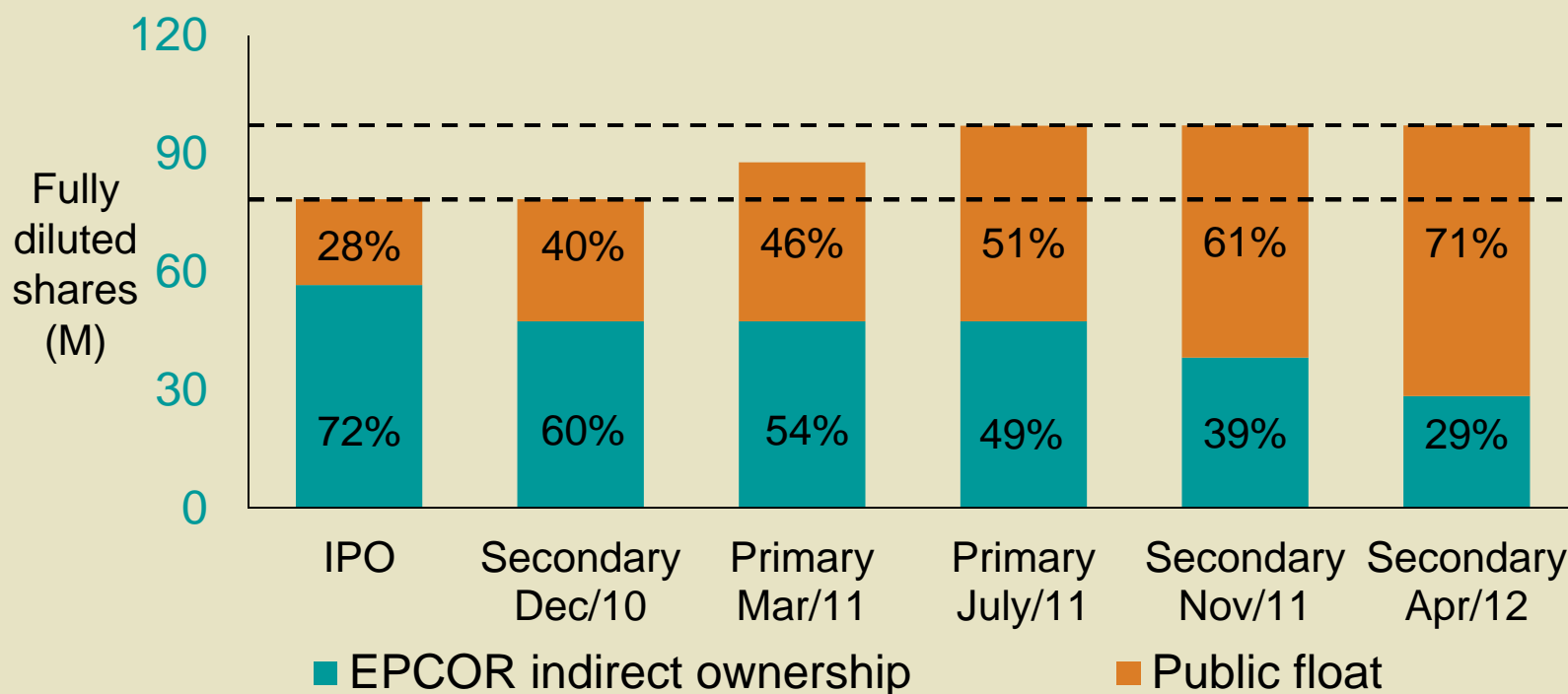
Apr-Dec 2012	2013	2014
Hedged positions (% hedged)		
73%	20%	5%
Average hedged prices		
Mid-\$60/MWh	Mid-\$60/MWh	Low-\$60/MWh

- Sensitivity analysis⁽¹⁾ to +/- \$5/MWh change in Alberta power prices
 - 2012: +/- \$12M to EBITDA
 - 2013: +/- \$29M to EBITDA
 - 2014: +/- \$33M to EBITDA

(1) Based on Q1/12 corporate financial projection.

Financial strength and access to capital

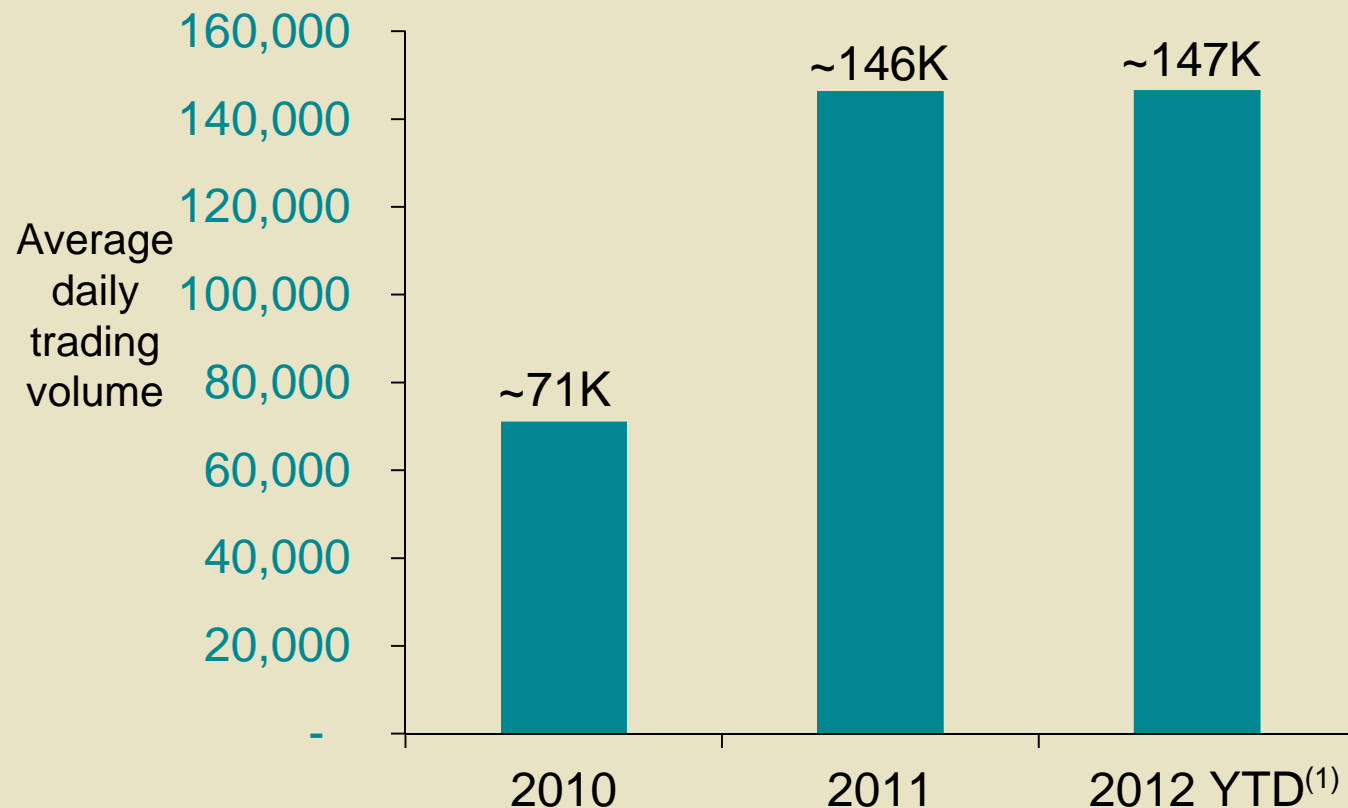
- BBB investment grade credit rating from S&P and DBRS
- ~\$1.2B in debt issues since IPO
- ~\$1.3B raised in equity markets since IPO; public float now 71% of ownership



- At ~37%, debt-to-capital ratio remains below long-term target of 40% - 50%

Public float growth has enhanced liquidity

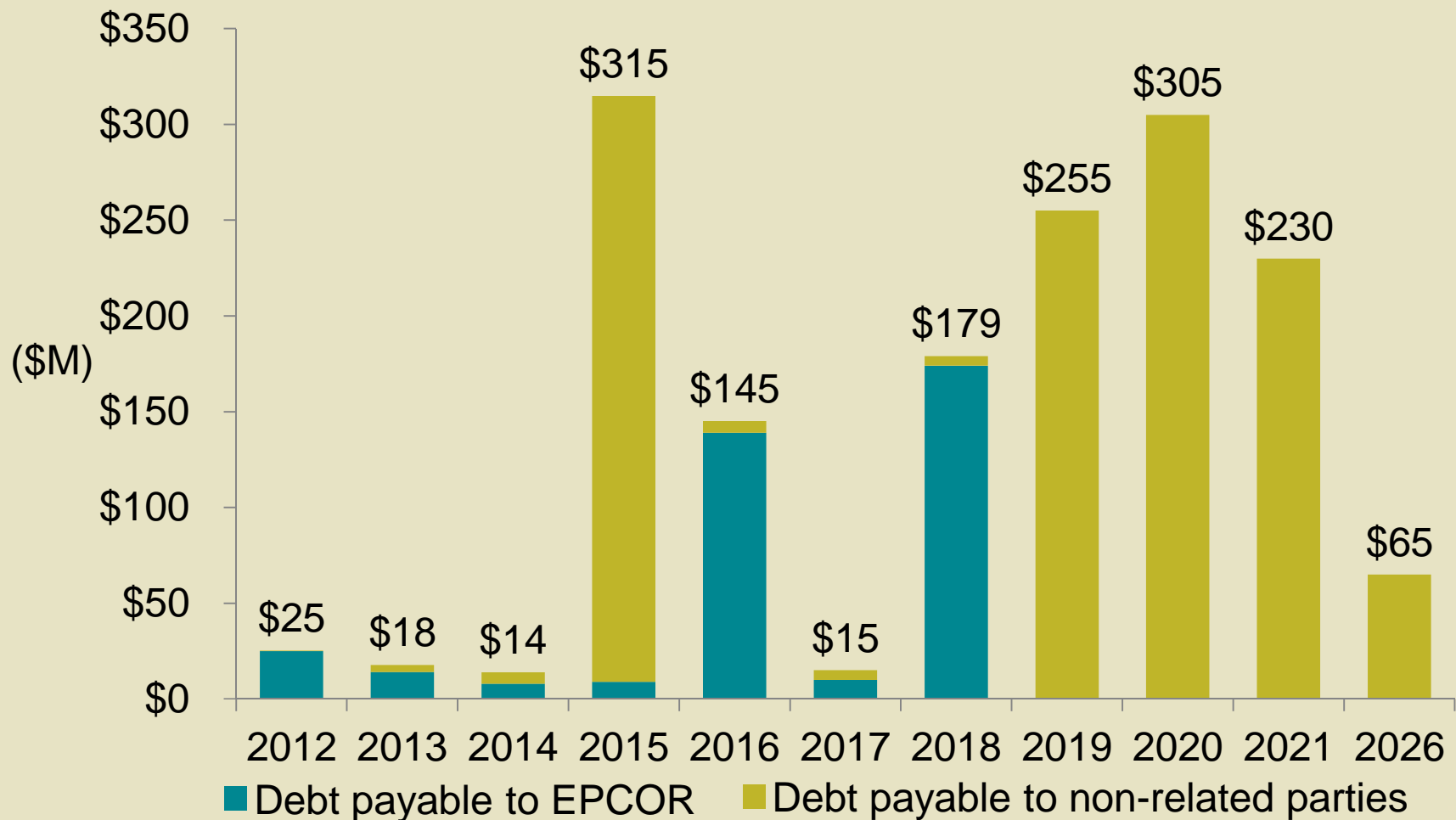
- Added to S&P/TSX Composite Index in June 2011
- Average daily trading volume has doubled compared to 2010



(1) As of May 11/12.

Debt maturity schedule

Well spread-out debt maturities are supported by long asset lives



Financial performance – Q1/12

\$M, except per share amounts	Q1/12	Q1/11	% Change
Revenues and other income ⁽¹⁾	\$366	\$376	(2.7%)
EBITDA ^(1,2)	\$139	\$72	93%
Earnings per share	\$0.66	\$0.06	n.m.
Normalized earnings per share	\$0.46	\$0.34	35%
Funds from operations excluding non-controlling interests in CPILP	\$116	\$83	40%
Cash flow per share	\$1.19	\$1.04	14%

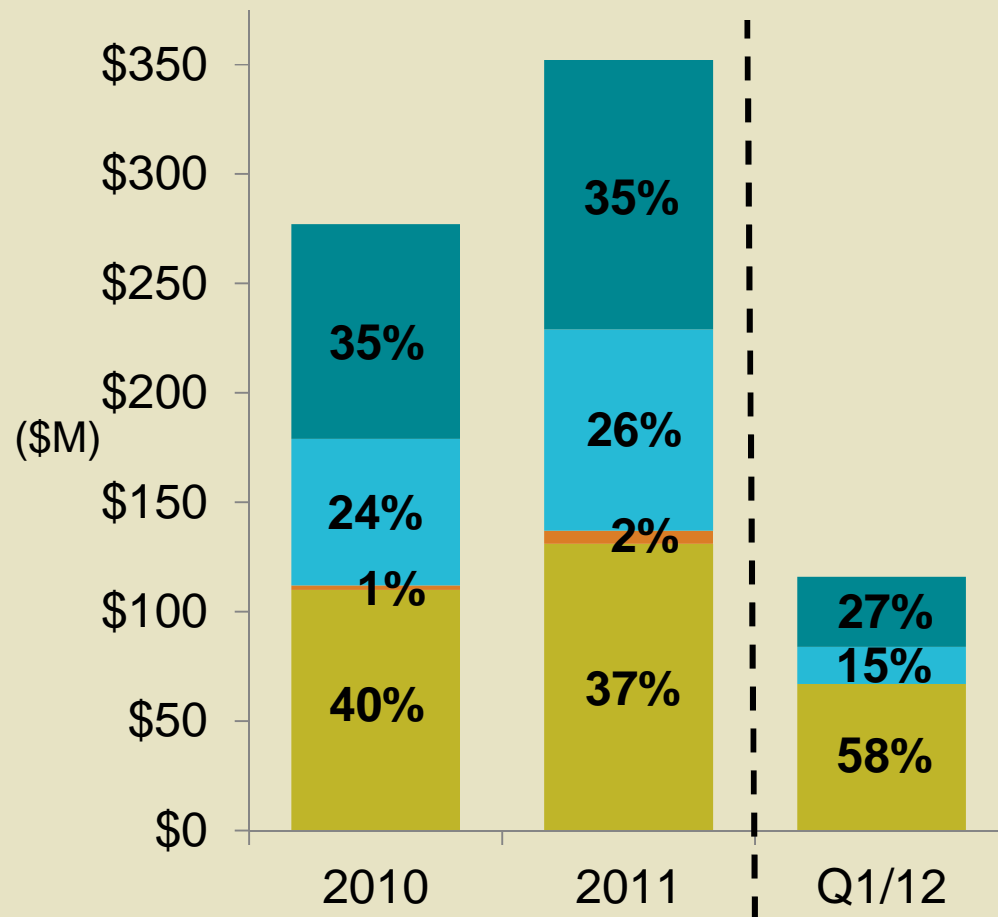
Financial results in line with expectations despite lower AB power prices

(1) Before unrealized fair value changes in derivative instruments, natural gas inventory held for trading, and foreign exchange and natural gas contracts. Excludes CPILP.

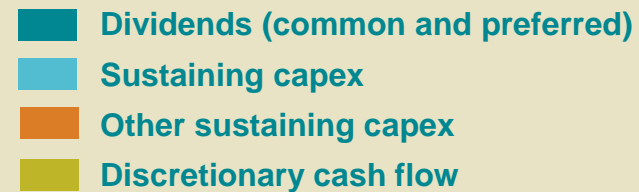
(2) Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses and gains on acquisitions and disposals.

Strong cash flow generation

FFO (excluding CPILP)



- Discretionary cash flow⁽¹⁾ represented 37% of Funds from operations in 2011
- Keephills 3 will start generating full year cash flows in 2012
- Halkirk and Quality Wind expected to be in operation in Q4/12



(1) Discretionary cash flow is a non-GAAP financial measure, see slide 34 for reconciliation.

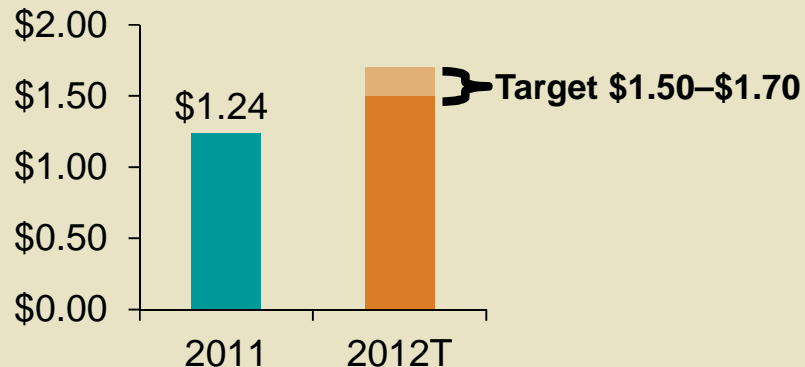
2012 Outlook

- Normalized EPS is now expected to be slightly under the low end of the \$1.50 - \$1.70 target range based on revised forecast power prices and spark spreads
 - Revised Alberta forward power prices of \$68/MWh compared to original forecast of \$74/MWh
- New England facilities are now expected to contribute \$41M of EBITDA in 2012, \$10M lower than previous disclosure
 - Region experienced significantly lower power prices in Q1/12 due to warmer than expected winter
 - Lower EBITDA primarily attributable to decreased forward commodity prices resulting in decreased spark spreads and energy margins
 - Revised full year spark spreads have decreased by ~US\$2/MWh compared to original forecasts
- In 2012, no primary common share equity issuance expected other than DRIP, absent an acquisition
- Development project financing expected to be funded through MTN and preferred share issues

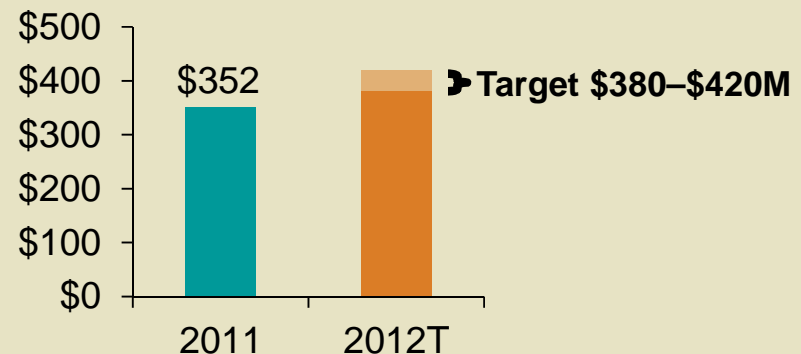
2012 Financial targets

Deliver on growth in cash flow and normalized EPS

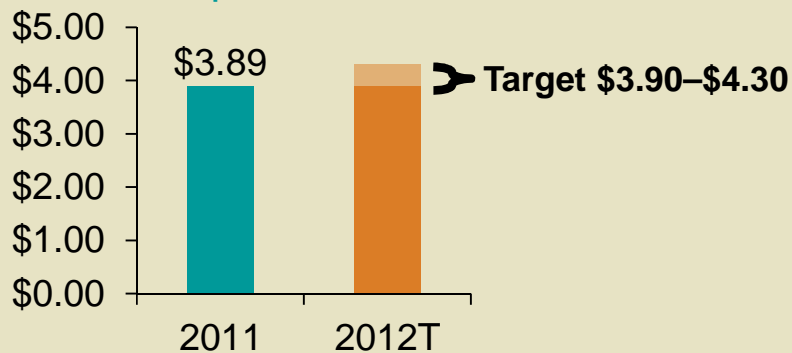
Normalized EPS



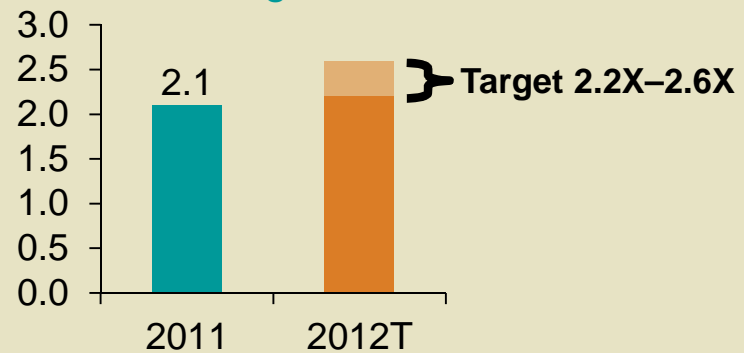
Funds from operations



Cash flow per share

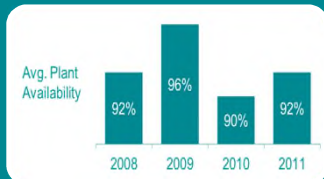


Dividend coverage ratio



Normalized EPS expected to be slightly under the low end of target range should lower power prices continue throughout 2012

Summary



Large, high quality generation portfolio

Young and modern fleet with proven operating history

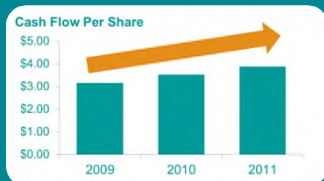


Diversified portfolio in attractive North American markets

Strong exposure to attractive Alberta power market



Long-term contracts and merchant position provides stable cash flows and upside opportunities



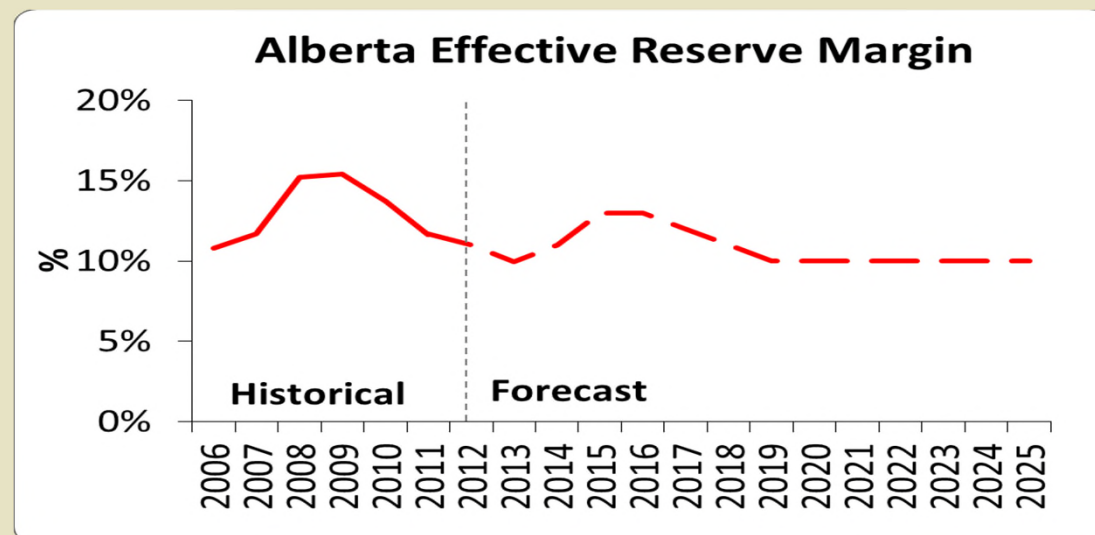
Financial strength with access to capital

Investment grade credit rating

Strong cash flow generation

AB reserve margin forecast

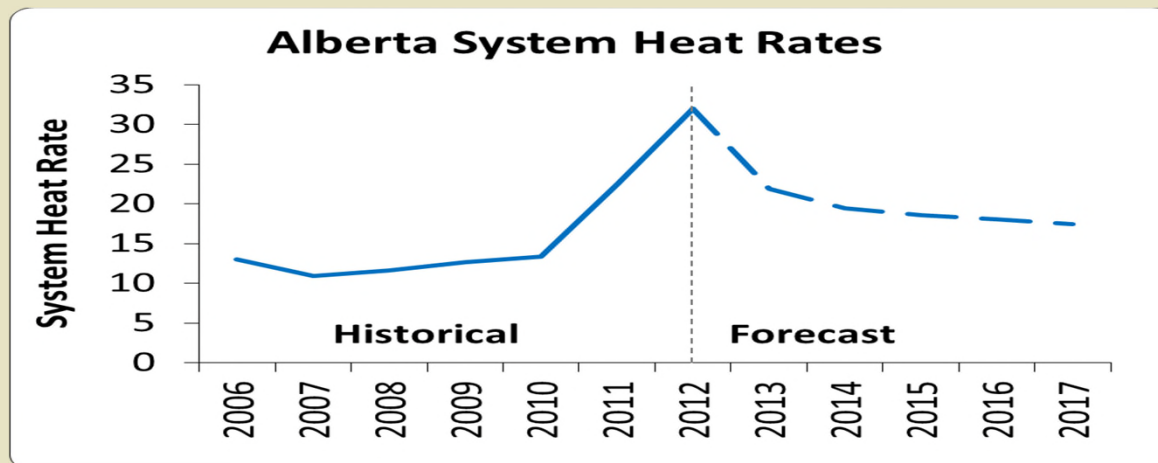
- Supply-demand balance (reserve margin) expected to be tight until Shepard (800 MW) COD in 2015, and then gradually tighten through the early 2020s
 - Bringing significant upside to power prices in AB market
- When AB net reserve margin falls below 10%, new generation will typically be economic
- Significant opportunities in the late decade or early 2020s for developers of generation as coal unit retirements kick in



Source: Internal forecast - Spring 2012

AB system heat rate forecast

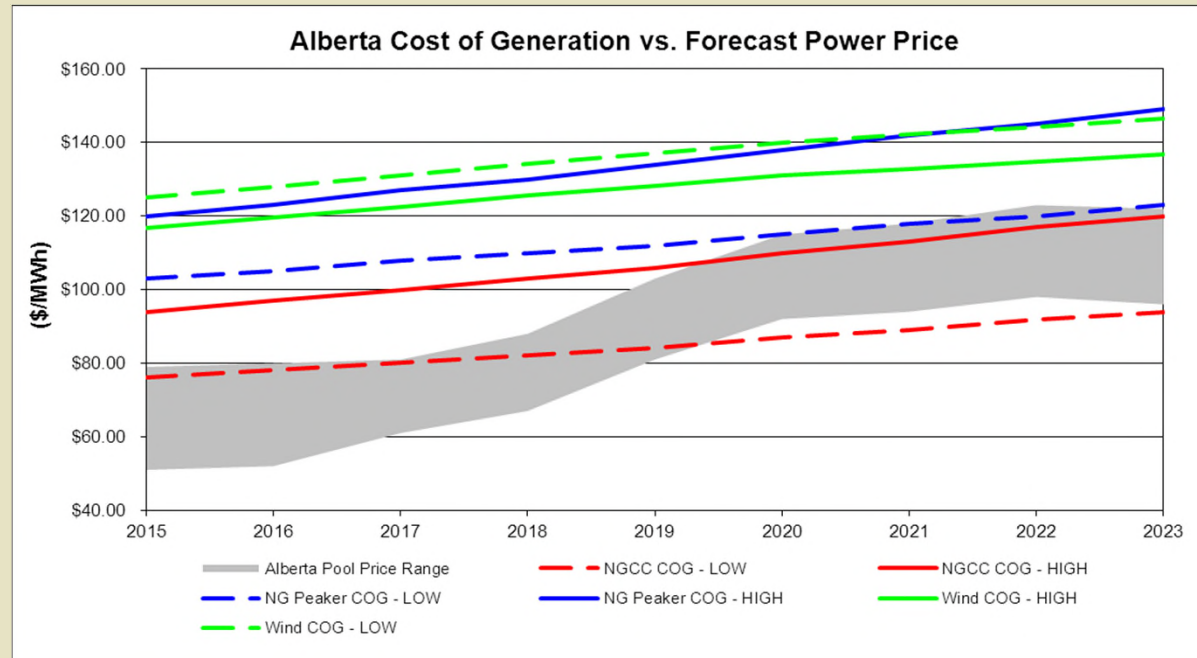
- Portfolio bidding keeping prices high and lowering NG prices driving system heat rates high
- Alberta expected to grow at above-national average rates due to the impact of oil sands activity
- Capital Stock Turnover expected to drive major coal retirements with upward impact on prices 2015 onwards
- As coal retires, natural gas generation will be increasingly on the margin
- System heat rates declining but still above historical levels



Source: Forward Prices May 2012

AB cost of generation (COG)

- Sustained higher power prices are required to incent new builds
- Current market fairly well-supplied (COD Keephills 3 in 2011), significantly tighter now due to shutdown of Sundance 1 & 2



Source: Internal forecast – Spring 2012

- New generation likely to be baseload NGCC to replace retiring coal units
- Wind development not economic in AB without RECs
- If Capital Stock Turnover proceeds, market likely to be relatively balanced through the 2020s as coal plant retirements balanced by NGCC additions

Appendix

AB power market (new builds/retirements)⁽¹⁾

- New builds/retirements (major projects of 100+ MW) over the next 5 years based on internal assumptions

Project	Capacity (MW)	Developer	Type	COD year
Halkirk	150	Capital Power	Wind	2012
Shepard Energy Centre	800	Enmax	Combined cycle	2015
Facility	Capacity (MW)	Owner	Type	Retirement year
Sundance 1	280	TransAlta	Coal steam	2011
Sundance 2	280	TransAlta	Coal steam	2011

(1) Internal forecast – Spring 2012.

Appendix

Summary of assets

	<u>Genesee</u> <u>1</u>	<u>Genesee</u> <u>2</u>	<u>Genesee</u> <u>3</u>	<u>Keephills</u> <u>3</u>	<u>Joffre</u>	<u>Clover Bar</u> <u>Energy</u> <u>Centre</u>	<u>Clover</u> <u>Bar</u> <u>Landfill</u>	<u>Roxboro</u>	<u>Southport</u>
	Alberta Contracted		Alberta Commercial				Mid-Atlantic Contracted		
Electric Capacity	422 MW	430 MW	516 MW	495 MW	480 MW	243 MW	4.8 MW	88 MW	46 MW
% owned / operated	100 / 100	100 / 100	50 / 100	50 / 0	40 / 0	100 / 100	100 / 100	100 / 100	100 / 100
Location	Warburg, Alberta	Warburg, Alberta	Warburg, Alberta	Keephills, Alberta	Joffre, Alberta	Edmonton, Alberta	Edmonton, Alberta	Roxboro, North Carolina	Southport, North Carolina
Fuel	Coal	Coal	Coal	Coal	Natural gas	Natural gas	Landfill gas	Mixture of wood residuals, tire-derived fuel and coal	Mixture of wood residuals, tire-derived fuel and coal
Commercial Operations	1994	1989	2005	2011	2000	Unit 1 - 2008 Unit 2&3 - 2009	2005	1987	1987
PPA Expiry	2020	2020	Merchant	Merchant	Merchant	Merchant	Merchant	2021	2021

Appendix

Summary of assets (cont'd)

	<u>Kingsbridge 1</u>	<u>Miller Creek</u>	<u>Brown Lake</u>	<u>Island Generation</u>	<u>Tiverton</u>	<u>Rumford</u>	<u>Bridgeport</u>
	Ontario & British Columbia Contracted				US Northeast Commercial		
Electric Capacity	40 MW	33 MW	7 MW	275 MW	279 MW ⁽¹⁾	270 MW ⁽¹⁾	540 MW ⁽¹⁾
% owned / operated	100 / 100	100 / 100	100 / 100	100 / 100	100 / 100	100 / 100	100 / 100
Location	Goderich, Ontario	Pemberton, BC	Near Prince Rupert, BC	Campbell River, BC	Tiverton, Rhode Island	Rumford, Maine	Bridgeport, Connecticut
Fuel	Wind	Hydro	Hydro	Natural gas	Natural gas	Natural gas	Natural gas
Commercial Operations	2006, 2001	2003	1996	2002	2000	2000	1999
PPA Expiry	2026 / 2027	2023, extendible to 2033 at BCH's option	2016	2022	Merchant	Merchant	Merchant

(1) Represents net winter capacity. Tiverton, Rumford and Bridgeport have nominal generation capacities of 265, 265, and 520 megawatts, respectively.

Appendix

Summary of projects under development

	<u>Halkirk</u>	<u>K2 Wind Ontario</u>	<u>Quality Wind</u>	<u>Port Dover & Nanticoke</u>
	Alberta Commercial & Contracted	Ontario & British Columbia Contracted		
Electric Capacity	150 MW	270 MW	142 MW	105 MW
% owned / operated	100 / 100	33.3% owned	100 / 100	100 / 100
Location	Halkirk, Alberta	In the township of Ashfield-Colborne-Wawanosh, Ontario	Near Tumbler Ridge, BC	Located in an area that covers the counties of Norfolk and Haldimand, Ontario
Fuel	Wind	Wind	Wind	Wind
Expected Commercial Operations	Q4/12	2014	Q4/12	Q4/13
PPA Expiry	~40% - 45% of total revenues from 20-year REC sale agreement / Merchant	20-year PPA with Ontario Power Authority for \$135/MWh	25-year EPA from BC Hydro	20-year PPA with Ontario Power Authority for \$135/MWh
Expected Capital Cost	\$357M, including acquisition costs (\$33M)	Expected total project capex of \$874M; CPC's expected capex for project is \$46M	\$455M	\$340M

Forward-looking information

Forward-looking information or statements included in this presentation are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this presentation is generally identified by words such as will, anticipate, believe, plan, intend, target, and expect or similar words that suggest future outcomes.

Material forward-looking information in this presentation includes information with respect to: (i) expectations related to future earnings and funds from operations; (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets; (iii) expectations regarding fuel supply and pricing; (iv) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures and dividends; (v) expectations for the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings; (vi) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies; (vii) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions; and (viii) expectations regarding plant availability and capital expenditures for maintenance.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance; (iii) business prospects and opportunities including expected growth and capital projects; (iv) status of and impact of policy, legislation and regulations; (v) effective tax rates; and (vi) other matters discussed under the Performance Overview and Outlook sections in Q1/12 Management's Discussion and Analysis.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) power plant availability and performance including maintenance expenditures; (ii) changes in electricity prices in markets in which the Company operates; (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction; (v) ability to fund current and future capital and working capital needs; (vi) changes in energy commodity market prices and use of derivatives; (vii) changes in market prices and availability of fuel; and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in Q1/12 Management's Discussion and Analysis for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Non-GAAP financial measures

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on acquisitions and disposals (EBITDA), (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) dividend coverage ratio, (vi) normalized earnings attributable to common shareholders, and (vii) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to gross income, net income, net income attributable to Shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from Management's perspective.

Reconciliations of these Non-GAAP financial measures are contained in the Company's Management's Discussion and Analysis dated April 26, 2012 for the three months ended March 31, 2012 which is available under the Company's profile on SEDAR at www.SEDAR.com and on the Company's website at www.capitalpower.com.

Discretionary cash flow

The Company uses discretionary cash flow as a measure of the Company's available cash to reinvest into the business after paying sustaining capital expenditures and declared dividends and distributions to common and preferred shares. Discretionary cash flow is not a defined financial measure according to GAAP and does not have standardized meaning prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. This measure should not be considered an alternatives to net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, this measure is provided to complement GAAP measures in the analysis of the Company's results of operations from Management's perspective.

A reconciliation of "net cash flows from operating activities" to "funds from operations excluding non-controlling interests in CPILP" is referenced under Non-GAAP Financial Measures in the Company's Q4/11 and Q1/12 Management's Discussion and Analysis, which is available under the Company's profile on SEDAR at www.SEDAR.com and on the Company's website at www.capitalpower.com.

A reconciliation to Funds from operations excluding non-controlling interests in CPILP is as follows:

(unaudited, \$millions)	Year ended Dec 31		Three months ended Mar 31	
	2011	2010	2012	2011
Funds from operations excluding non-controlling interests in CPILP	\$ 352	\$ 277	\$116	\$83
CPLP sustaining capital expenditures	(92)	(67)	17	9
CPLP's share of CPILP sustaining capital expenditures	(6)	(2)	n/a	1
Funds available for distribution	\$ 254	\$ 208	\$99	\$73
Common share dividends declared	60	30	19	12
Distributions to exchangeable common limited partnership unitholders of CPLP declared	57	68	12	15
Preferred share dividends declared	6	-	1	2
Total dividends and distributions declared	\$ 123	\$ 98	\$32	\$29
Discretionary cash flow	\$ 131	\$ 110	\$67	\$44

{ Investor Relations Contacts

Randy Mah
Senior Manager
(780) 392-5305
rmah@capitalpower.com

Chris Williams
Senior Analyst
(780) 392-5105
cwilliams@capitalpower.com

