Q. Referring to page 61 of Ms. McShane's direct testimony, please provide the sources referred to in Footnote 64.

A. The referenced allowed ROEs are found in Ms. McShane's Schedule 5.

DBRS, *Credit Rating Report: TransCanada Pipelines Ltd., September 8, 2006* is provided as Attachment A.

DBRS, *Credit Rating Report: Terasen Inc., September 11, 2006* is provided as Attachment B.

DBRS, *Credit Rating Report: Canadian Utilities Ltd., January 31, 2007* is provided as Attachment C.

DBRS Rating Report
TransCanada Pipelines Ltd.

TransCanada PipeLines Limited

Report Date:	September 8, 2006
Press Release:	September 8, 2006
Previous Report:	August 30, 2005

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RATING

Rating	Trend	Rating Action	Debt Rated
A	Stable	Confirmed	First Mortgage Bonds
A	Stable	Confirmed	Unsecured Debentures & Notes
R-1 (low)	Stable	Confirmed	Commercial Paper
Pfd-2	Stable	Confirmed	Preferred Securities (COPrS)
Pfd-2 (low)	Stable	Confirmed	Preferred Shares – cumulative

RATING HISTORY

	Current	2005	2004	2003	2002	2001
First Mortgage Bonds	A	A	A	A	A	A
Unsecured Debentures & Notes	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Preferred Securities (COPrS)	Pfd-2	Pfd-2y	Pfd-2y	Pfd-2y	Pfd-2y	Pfd-2y
Preferred Shares - cumulative	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

RATING UPDATE

TransCanada PipeLines Limited (TCPL or the Company) has embarked on a significant growth phase composed of large-scale pipeline and power projects. Its two largest developments, the Keystone Pipeline (Keystone) and the restart of Bruce Power Inc.'s two units (Bruce Restart) would account for $4.2 billion (64%) of the $6.6 billion estimated capital program planned for 2006 to 2010, its largest program ever. Keystone marks TCPL's re-entry into the crude oil pipeline business (despite Enbridge Inc.'s competing Alberta Clipper pipeline project), and Bruce Restart enhances TCPL's capability in the growing Ontario power market, both with long-term expansion prospects. Selective infrastructure projects to provide further storage and new liquefied natural gas (LNG) facilities are also being reviewed. The foregoing projects entail execution risks in a highly competitive market, particularly in western Canada, and would require external financing, although largely supported by long-term contracts with mostly creditworthy counterparties. Dominion Bond Rating Service (DBRS) expects TCPL to continue to exercise financial and operational discipline during the growth phase to keep its credit metrics in line with the current credit ratings.

TCPL's portfolio of new projects reinforces its continued effort to re-balance its business mix by focusing on stable regulated pipelines (75% of EBIT in 2005), while pursuing higher return power developments. The purchase of Gas Transmission Northwest Corporation (GTN) and North Baja System in late 2004 has in part alleviated concerns relating to its Canadian pipelines, which have experienced lower returns on a declining asset base, and continued de-contracting, affecting its competitiveness. GTN also reaches the growing California and Mexico markets, the latter of which could connect to new LNG terminals, over time. (Continued on page 2.)

RATING CONSIDERATIONS

Strengths

- Integrated transmission system from western Canada
- Stable financial profile based on regulated operations
- Substantial growth opportunities in pipelines and power Long-term supply and growing demand for natural gas

Challenges

- Balance sheet pressure and execution risk from significant growth projects
- Increased business risk with non-regulated investments
- Excess pipeline capacity delaying full re-contracting
- Regulatory restraints on profitability and coverage ratios
- Potential subordination of cash flow from equity investments

FINANCIAL INFORMATION

	6 months	6 months	Roling 12 mos.	For the year ended December 31			
Proportional Consolidation	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
Net income before extras. ($ millions)	461	408	976	923	837	831	772
Cash flow before extras. ($ millions)	1,083	978	2,067	1,962	1,585	1,810	1,827
Return on common equity	11.6%	11.3%	12.7%	12.3%	12.5%	13.1%	12.8%
Total debt in capital structure*	62.2%	63.9%	62.2%	61.9%	64.1%	64.2%	65.2%
Cash flow/total debt (times)*	0.17	0.16	0.16	0.00	0.13	0.15	0.16
(Cash flow - divs.)/net capex	1.22	4.62	2.38	14.67	13.77	3.15	2.15
EBIT interest coverage (times)	2.53	2.25	2.46	2.32	2.35	2.32	2.29
Fixed-charges coverage (times)	2.26	1.99	2.17	2.03	2.15	2.10	2.08
Volume shipments (Mainline) (bcf)	1,144	1,044	n.a.	2,997	2,621	2,628	2,630
Volume shipments: Alberta Syst.(bcf)	2,070	1,979	n.a.	3,999	3,909	3,883	4,146

*Including joint venture non-recourse debt and portions of preferred securities/shares. n.a. = not available.

THE COMPANY

TCPL is a leading integrated energy services company in North America, involved in transmission of natural gas (consolidated delivery capacity of 12 billion cubic feet per day) and power generation (6700 megawatts). Its extensive network consists of 41,000 kilometres (or 25,600 miles) of pipelines.

AUTHORIZED PRINCIPAL COMMERCIAL PAPER AMOUNT

Limited to $1.5 billion.

Notes: All figures are in Canadian dollars unless otherwise noted.
The Preferred Securities (COPrS) have certain unique covenants that give them equity-like characteristics.

RATING UPDATE (Continued from page 1.)

GTN's rate case application submitted in mid-2006 may partly mitigate re-contracting issues at GTN caused by recent shipper bankruptcies. The higher equity thickness approved in the past three years for all of TCPL's Canadian pipelines to the 35% to 36% level (from 33%) is indicative of the regulatory authorities' awareness of the rising competitive pressures in Canada. However, the allowed ROE of below 9% approved for 2006 will affect short-term earnings and cash flow from the pipeline segment.

For the un-regulated power segment, which carries higher risk but higher margins than pipelines, TCPL has focused on adding low risk, base load assets, or those supported by long-term contracts. The commodity price support and capital cost sharing arrangements negotiated with the Ontario Power Authority (OPA – rated AA (low) with a Stable trend) for Bruce Restart is a case in point, reducing much of the project risk. The $1.3 billion purchases in 2005 of the hydroelectric power assets in New England, and the Sheerness Power Purchase Arrangements also reflect this strategy. The pipelines and power acquisitions should supplement cash flow required to fund longer term projects, including the northern gas developments at Mackenzie Delta (Mackenzie – albeit delayed by regulatory and aboriginal issues), and Alaska expected by early to mid next decade. TCPL retains a potential 5% to 30% or more interest in Mackenzie, which would connect to its Alberta System, supplying much of the natural gas needed for growing Canadian oil sands production.

TCPL's biggest challenge is to manage its largest-ever capital program of up to $6.6 billion to 2010 (excluding Mackenzie and Alaska), without undue delays and cost overruns, or overleveraging its balance sheet. There are no major debt maturities during the growth period to 2010. Future international ventures should be supported by long-term contracts, as in the case of the Mexican pipeline project, to minimize the attendant political and other risks.

RATING CONSIDERATIONS

Strengths

(1) The Company owns the largest integrated transmission system for natural gas in Canada, connecting the Western Canada Sedimentary Basin (WCSB) to the growing markets of eastern Canada, the northern region of the United States, and through the GTN purchase in 2004 (for US$1.7 billion) to California and Mexico. The Alberta System [NOVA Gas Transmission Ltd. (NGTL) – see separate report] dominates the Alberta market, shipping about two-thirds of the natural gas produced in the WCSB, or 17% of the production in North America. Over 50% of the shipments are exported to the United States. The Canadian Mainline, connecting with the Alberta System, is the predominant player in the export pipeline system to the key U.S. Midwest market.

(2) TCPL has maintained financial flexibility and stable cash flow based mostly on its regulated transmission business. Pipelines will likely continue to represent about 75% of the Company's earnings as in 2005. The Company's focus on the core transmission system in North America, and the higher margin power sector in the past four years, has resulted in an improved financial profile. Debt-to-capital improved to 62% as of June 30, 2006, with cash flow-to-debt at 0.17 times (68% and 0.12 times, respectively, in 2001) and solid fixed charge coverage of 2.3 times.

(3) Future prospects are underpinned by substantial growth projects to 2010 and beyond. Capital investments estimated at $6.6 billion to 2010 are expected to provide the much needed infrastructure to meet the growing energy requirements in North America and the expanding power market in Ontario.

(4) There is sufficient supply of natural gas in western Canada to support current pipeline capacity based on the 2005 estimates of the National Energy Board (NEB) of over ten-year reserve life at current production levels. Despite the recent softening of prices, longer-term increased demand for natural gas should generate incremental supply, raising the value of current pipeline capacity. Northern gas developments underpin longer-term supply prospects. The growing U.S. demand, driven by gas-fired electricity generation projects, the favourable commodity pricing environment, and growing oil sands developments have fuelled increased drilling activities in western Canada where the Alberta System dominates.

Challenges

(1) External financing required to support the numerous potential greenfield projects over the next four to five years (estimated cost of $6.6 billion) could pressure the balance sheet, given the time lag between capital deployment and cash flow generation. Execution risks in terms of project delays and cost overruns will need to be monitored in a highly competitive market for labour and materials. Long-term commitments from counterparties, such as, ConocoPhillips (rated A (low)) for Keystone and OPA's capital sharing for Bruce Restart, should partly mitigate the project risks.

(2) TCPL's strategic moves outside the regulated area with a focus on Power expansions could have credit rating implications. The Power operation accounted for 25% of net earnings in 2005, compared with 18% in 2002, mainly through the Bruce Power purchase in 2003 and subsequent acquisition of the USGen New England, Inc. (USGen) and Sheerness power assets in 2005, as well as the current Bruce Restart. However, the Company has funded these acquisitions conservatively to-date and has used long-term contracts to mitigate risk, where attainable.

(3) Significant pipeline de-contracting has occurred since 1999. While TCPL's cost of service arrangements with shippers eliminate throughput risk, tolls could be driven up, reducing its competitiveness. A shortage of gas deliverability in western Canada has contributed to de-contracting exacerbated by competition from Alliance/Vector Pipelines, which are supported by long-term contracts and competitive tolls. TCPL's Mainline System virtually acts as a "swing pipeline", but it is protected from throughput risk under the regulated tolling arrangements.

(4) TCPL's profit margins and coverage ratios, while acceptable due to cost control efforts to enhance performance, are constrained by the regulatory regime. The

higher deemed equity component (36% versus 33%) approved during the past three years for all its Canadian pipelines (35% for Alberta system) (see Regulation section) should help earnings, together with ongoing refinancing of longer term debt at lower interest rates.

(5) Potential subordination of cash flows from equity investments exists. The Company is expected to make significant investments in the future in equity ventures, such as the Bruce Restart, and potentially in projects where there will be project debt used in financing (not expected in the case of Bruce Restart and Keystone). To the extent that this occurs significantly, it could impact the cash flow metrics of TCPL as monies will only flow to TCPL to the extent that dividends are paid as determined by all of the equity holders, or debt is serviced at the project entity. Currently reported equity earnings exceed distributions from these investments, but this issue is not considered significant enough to affect TCPL's credit metrics.

PROPOSED PROJECTS

Major Capital Projects ($ millions)		Capacity	Project Cost	Completion	Comments
Tamazunchale pipeline project, Mexico	USD	170 mmcfd	181	Dec. 2006	26-year contract with Pemex.
Bruce Restart ($47.9% interest in A)	CAD	1,500 MW	2,130	late 2009	Long-term contract with OPA with price support and capital cost sharing.
Keystone crude pipeline project *	CAD	435 kbd	2,100	2009/2010	About 80% of capacity covered by long-term commmitments.
North Baja Pipeline LLC - expansion	USD	up to 2.2 bcf	290		
Edson Natural Gas Storage	CAD	50 bcf	200	late 2006	
Becancour, Québec	CAD**	90 MW	0	2006	] Covered by long-term contracts
Cartier Wind Energy Inc. (50% interest), first 2 phases	CAD**	740 MW	370	2006/2007	]
Gros Cacouna, Québec LNG facility	CAD	500 mmcfd	660	2010	] To negotiate long-term contracts covering capacity
Broadwater Energy LNG regas faciltiy	USD	1 bcfd	700	2010	]
			6,638		
Potential Projects					
Mackenzie Delta pipeline		1.2 bcfd	TBD	2010/2011	
Alaska pipeline		4.0 bcfd	TBD	TBD	

*At ConocoPhillips's option to acquire 50% interest. **DBRS estimate.

- More than half of the proposed capital projects totalling $6.6 billion (equivalent) will require regulatory and other approvals, notably Keystone and the LNG projects.
- Most of the new developments are supported by long-term contacts, or memorandum of understanding indicating interest in long-term commitments, providing stability of cash flow.
- For instance, the restart of Bruce A Units 1 & 2 (1,500 megawatts) is supported by long-term contracts with the OPA providing power price support and sharing of construction cost overruns (25%-75% depending on circumstances). A collateral benefit is OPA's commitment to provide fixed price/floor price contracts respectively on the existing Bruce A and B operating units, previously mostly exposed to the spot market.

REGULATION

Canadian Mainline

- Regulated by the NEB on a cost-of-service basis, effectively eliminating short-term throughput risk.
- Cost savings on operation, maintenance, and administration (OM&A) accrue to TCPL with all other elements, such as interest costs, flow through 100% to the shippers.
- Reached a settlement with its Canadian shippers in February 2005 regarding 2005 tolls and providing opportunities for incentive earnings.

<u>2006 Tolls and Tariff Application Approved in March 2006</u>:

- 36% deemed common equity remains.
- ROE of 8.88% for 2006 (9.46% in 2005). ROE based on annual adjustment mechanism tied to long-term government bond yields.
- Rate base of $7.8 billion and net revenue requirement of $1.8 billion (down 5% from 2005).
- Eastern zone toll effective January 1, 2006, of $0.945 per gigajoule (GJ) compared with interim tolls of $1.222/GJ.

Alberta System (NGTL)

- Regulated by the Alberta Energy and Utilities Board. Effective cost-of-service and distance-based protected from short-term throughput risk.
- Cost savings similar to Mainline.
- Reached agreement with shippers in March 2005 on revenue requirements for 2005-2007.

<u>GTN:</u>

- Subject to the U.S. Federal Energy Regulatory Commission (FERC) regulation of interstate pipelines. Regulated on complaint basis.
- The rate design stemming from Order 636 issued in 1992 assures gas pipelines full cost recovery, including ROE and income taxes over the capacity reservation component of rates. The foregoing applies to firm contracts, regardless of usage.
- In June 2006, a new rate case application was submitted to amend that approved in 1995, requesting effectively a 70% increase in maximum full-haul unit rate to US$0.45/dekatherm: (1) 14.5% ROE versus 12.2% previously. (2) Deemed equity of 62.99% versus 47%. (3) Rate base of approximately US$868 million versus

US$952 million. (4) Throughput of 327,067 versus 367,129 million dekatherm-miles.

- Permitted to recover 96.4% of its fixed costs through reservation charges on long-term capacity with balance of the tariff based on the commodity charge on actual volumes transported.
- GTN's operating results are not significantly affected by variances in throughput.

Significant Joint Venture Investments

- U.S. pipelines are subject to FERC rulings.
- Higher ROE (12% to 14%) and deemed equity (30% to 40%) are allowed compared with the Canadian pipelines.

EARNINGS

Net Income Before Extras.*											
($ millions)	6 months	6 months	Roling 12 mos.	For the year ended December 31							
Transmission	June 30, 2006	June 30, 2005	June 30, 2006	2005	%	2004	%	2003	%	2002	%
Alberta System	67	74	143	150	18%	150	19%	190	23%	214	27%
Canadian Mainline	120	149	254	283	34%	272	35%	290	35%	307	38%
B.C. System	3	3	6	6	1%	7	1%	6	1%	6	1%
Foothills	11	11	21	21	3%	22	3%	20	2%	17	2%
GTN	27	33	65	71	9%	14					
Subtotal (wholly owned)	228	270	489	531	64%	465	60%	506	61%	544	68%
N.A. pipeline investments	38	43	92	97	12%	107	14%	116	14%	109	14%
Transmission	266	313	581	628	75%	572	73%	622	76%	653	82%
Bruce Power **	69	28	169	129	15%	86	11%	0			
Other	105	45	136	75	9%	123	16%	201	24%	146	18%
Energy**	174	73	305	204	25%	209	27%	201	24%	146	18%
Subtotal	440	386	886	832	100%	781	100%	823	100%	799	100%
Corp. & unallocated	21	22	90	91		56		8		(27)	
Net Income Bef. Extras.*	461	408	976	923		837		831		772	
Extraordinary items	64	62	372	370		194		30		33	
Net income - continued oper.*	525	470	1,348	1,293		1,031		861		805	
Net income - discont. oper.*	28	0	28	0		52		50		0	
Preferred dividends	(36)	(38)	(82)	(84)		(53)		(60)		(58)	
Reported net income*	517	432	1,294	1,209		1,030		851		747	
Throughput Volumes											
Canadian Mainline (bcf/d)				8.2		7.2		7.2		6.1	
Alberta System				11.1		10.8		10.6		11.4	

*Before preferred dividends, and net income as estimated by DBRS. **Previously designated as Power, which now also includes natural gas storage and LNG businesses.

Six months ended June 30, 2006 (H1 2006):

Higher earnings before extraordinary items of $461 million (+13%) attributable to significantly higher earnings from Energy (+138%) across the board more than offset lower earnings (-16%) from Mainline, Alberta and GTN as a result of lower ROE on a declining rate base for the former two with GTN affected by lower volumes.

- As a result, Energy (mainly Power) contributed 40% to net earnings versus 19% in H1 2005. Bruce Power is a key contributor primarily due to higher volumes from fewer outages together with higher margins from the western and eastern operations and recent acquisitions.
- These factors coupled with higher earnings from natural gas storage (Cross Alta) more than compensated for the loss of earnings from the sale of the TransCanada Power LP (Power LP) in Q3 2005.
- Reported net income included $33 million from reduced tax rates, $18 million from a bankruptcy settlement at GTN and a $13 million after-tax gain on the sale of the Company's general partnership interest in Northern Border Partners LP.

2005:

Net earnings were up 10% primarily enhanced by the full-year impact of the acquisition of GTN in late 2004 and strong operating results at Bruce Power partly offset by higher expenses and income taxes at the Energy segment.

- Extraordinary items included gain on sale of the Power LP and the Indonesian pipeline assets totalling $308 million after tax.

Outlook

DBRS expects continued stable earnings underpinned by the regulated pipelines, which should remain the key contributor to earnings, as well as long-term government contracts with power price support secured for all Bruce Power units in October 2005.

- Near- to medium-term prospects are supported largely by Bruce Power and two recent power purchases, the imminent start-up of Becancour and the first two phased developments of the Cartier Wind project, all under long-term contracts.
- Earnings from these assets should offset lower pipeline earnings caused by lower ROEs on declining rate bases and reduced contracted volumes at GTN due to customer bankruptcies.
- Keystone, northern pipeline developments and potential new Bruce Power units, among others, will drive longer term prospects, supported by long-term commitments.

FINANCIAL PROFILE

(Excludes discontinued operations)	6 months	6 months	Rolling 12 mos.	For the year ended December 31			
($ millions)	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
EBITDA	1,634	1,483	3,198	3,047	2,926	2,952	2,987
Net income before extraordinary items	461	408	976	923	837	831	772
Depreciation, depl., & amortization	523	505	1,035	1,017	945	914	848
Deferred income taxes	(4)	26	30	60	77	230	247
Other	103	39	26	(38)	(274)	(165)	(40)
Operating Cash Flow	1,083	978	2,067	1,962	1,585	1,810	1,827
Capital expenditures – continued oper.	(630)	(243)	(1,141)	(754)	(476)	(391)	(599)
Dividends paid	(305)	(289)	(676)	(660)	(623)	(588)	(546)
Gross Free Cash Flow (Bef. Work. Cap.)	148	446	250	548	486	831	682
Changes in non-cash work. cap. items	(93)	(263)	121	(49)	34	112	33
Gross Free Cash Flow	55	183	371	499	520	943	715
Business acquisitions, net of cash	(358)	(632)	(1,043)	(1,317)	(1,516)	(570)	(228)
Divestitures	23	102	592	671	410	0	0
Other	(16)	50	(2)	64	(24)	(190)	(115)
Net Free Cash Flow	(296)	(297)	(82)	(83)	(610)	183	372
Inc. (dec.) in debt and equiv.	452	368	144	60	344	113	(568)
Inc. (dec.) in partnership units	0	0	0	0	88	0	0
Inc. (dec.) in pref. sec./pref. shares/sub. debt	(36)	(38)	2	0	0	(218)	0
Inc. (dec.) in common shares	13	29	28	44	32	65	50
Change in Cash – Continued Oper.	133	62	92	21	(146)	143	(146)
Capital expenditures – discont. oper.	0	0	0	0	0	0	0
Cash flow from discontinued operation	(28)	0	(28)	0	(6)	(17)	59
Change in Cash – Discontinued Oper.	(28)	0	(28)	0	(6)	(17)	59
Change in Cash For The Group	105	62	64	21	(152)	126	(87)
Total debt & equivalents	12,976	12,604	12,976	12,438	12,458	11,738	11,719
Total debt in capital structure	62.2%	63.9%	62.2%	61.9%	64.1%	64.2%	65.2%
Cash flow/total debt (times)	0.17	0.16	0.16	0.00	0.13	0.15	0.16
Fixed-charges coverage ratio	2.26	1.99	2.17	2.03	2.15	2.10	2.08

Positive gross free cash flow has been generated from the Company’s core pipeline business, which is stable and regulated, supplemented by Power to fund capex, dividends and minor purchases.

- The purchase of GTN in November 2004 required partial debt funding augmented by proceeds from the sale of non-core assets in the past two years, including the remaining Indonesian assets.
- Balance sheet leverage has since been reduced, despite the Sheerness and US Gen power asset purchases in 2005 ($1.3 billion). Debt-to-capital at 62% as of June 30, 2006, is in line with the higher 36% deemed equity thickness approved for all of its Canadian pipelines with adequate cash flow/debt support.

Outlook

- DBRS expects the Company’s financial metrics to remain stable and close to current levels, despite the substantial development projects in progress. Internally generated cash flow should be sufficient to cover dividends of over $600 million and annual capex estimated at the $1.5 billion level, near term.
- Large scale projects, including Keystone, Bruce Restart and northern gas developments, will provide the key impetus for longer term growth. Regarding Bruce Restart with the OPA commitments, TCPL should be able to withstand modest cost overruns, lower-than-historical plant availability and two-to-three year delays without materially affecting its financial profile.

DEBT MATURITIES

(December 31, 2005)

(1) TCPL's $1.5 billion commercial paper program is supported by $1.5 billion in credit facilities (no usage):

- $1.5 billion committed five-year facility to 2010, extendible on an annual basis.
- $500 million 364-day, renewable in December 2006 with a two-year term out.
- No material adverse change or rating trigger clause is in the loan agreement.

(2) Filed a Medium-Term Notes shelf for Cdn$1.5 billion and a base shelf for US$1.0 billion in December 2004, providing flexibility in future financing.

(3) Non-recourse debt of $862 million in joint ventures.

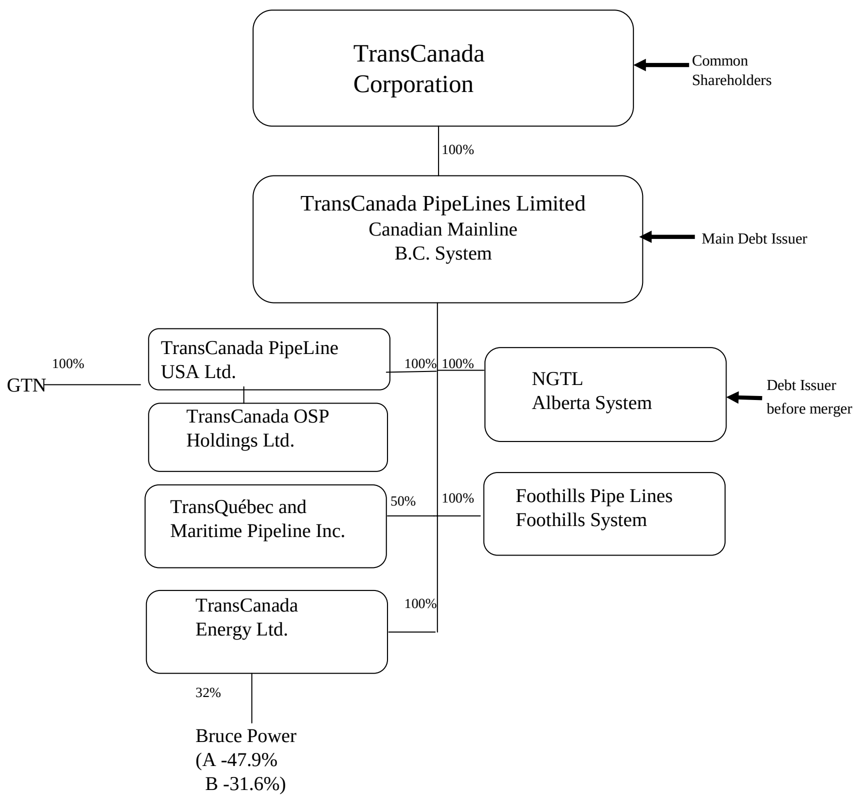
(4) Maximum guarantee obligations of $454 million.

- Debt maturities are well spread out during the heavy capital spending years to 2010. The Company has sufficient financial flexibility to access the capital markets for refinancing and growth capital, if required.

Debt Maturities (as of December 31, 2005):

($ millions)	2006	2007	2008	2009	2010	Beyond	Total
Long-term debt	393	604	547	742	416	8,750	11,036
% of long-term debt	3.6%	5.5%	5.0%	6.7%	3.8%	79.3%	100.0%
Non-recourse debt (joint venture)	68		29	69	98	668	937
% of long-term debt	7.3%		3.1%	7.4%	10.5%	71.3%	100.0%

HOLDING COMPANY STRUCTURE



- All new debt and equity issuance for the group is conducted through TCPL as was previously. Less than wholly owned subsidiaries, such as TransQuébec & Maritime Pipeline Inc. continue to fund their own capex and expansion projects. Bruce Power's funding requirements are met be its partners, including TCPL. GTN's refinancing was recently completed in its own name.
- There is potential increasing structural subordination issue on cash flow from equity investments, should TCPL significantly expand its portfolio, such as with the Bruce Restart, and other joint venture investments, where project debt is used in financing. In this regard, TCPL's cash flow metrics could be affected as it only has access to cash flow through dividend distributions as determined by all equity holders, and after the project debt is serviced.
- Bruce Restart's capital investment of approximately $2.1 billion to 2009 is expected to be mostly funded through TCPL's cash flow as well as distributions from the existing Bruce operation. Any remaining requirements should also be funded through TCPL.

SEGMENT ANALYSIS

	Net Income Before Extras. (NIBE)				Capex (2)				Return on Average Book Assets		
	2005	%	2004	%	2005	%	2004	%	2005	2004	2003
(Cdn$ millions)											
Alberta System	150	18%	150	19%	75	10%	87	18%	3%	3%	4%
Canadian Mainline	283	34%	272	35%	49	6%	43	9%	4%	3%	3%
B.C. System (2)	6	1%	7	1%	0	0%	1	0%	n.a.	n.a.	n.a.
Foothills	21	3%	22	3%	0	0%	1	0%	3%	3%	5%
GTN	71	9%	14	2%	0	0%	0	0%	4%	1%	n.a.
N.A. pipeline invest. (1) (2)	97	12%	107	14%	6	1%	55	12%	4%	5%	5%
Total transmission NIBE	628	75%	572	73%	130	17%	187	40%	4%	3%	4%
Bruce Power (3)	129	15%	86	11%	345	46%	285	51%	11%		
Other	75	9%	123	16%	280	37%			4%		
Energy (4)	204	25%	209	27%	625	83%	285	51%	9%	16%	16%
Total oper. income	832	100%	781	100%							
Corporate & unallocated	91		56								
Total NIBE	923	100%	725	100%	754	100%	472	100%			

(1) Excluding discontinued operations and before dividends on preferreds. (2) DBRS estimates for 2005.
(3) Capital lease proportionally consolidated based on 31.1% in Bruce B and 47.7% in Bruce A effective Oct. 31, 2005.
(4) Equivalent to previous Power segment. n.a. = not available.

Outlook

Transmission should remain the predominant segment contributing about three-quarters of earnings, given the development projects in progress.

- Power and other infrastructure assets will likely command a bigger share of capex in aggregate than pipelines, in view of the Bruce Restart, storage, and Beaucour and Cartier Wind projects currently underway.
- Power is expected to generate higher returns than the regulated transmission business. Return in terms of net income to average book assets estimated at 9% for energy and 4% for pipelines is for indicative purposes only, noting Bruce Power was proportionally consolidated only from October 31, 2005, and previously accounted for at an equity basis.

DESCRIPTION OF OPERATIONS

TransCanada PipeLines Limited

	% Ownership	Kilometres*	Dec. 31, 2005 LT Loans** ($ millions)	Description	2005 Deemed Equity	Allowed ROE 2006	Allowed ROE 2005	Regulation
Canadian Mainline	100.0%	14,900	4,233	Alberta to E. Canada and U.S.	36%	8.88%	9.46%	AEUB reg'd, incentive agreement
Alberta System	100.0%	22,700	2,258	Mainline and laterals in Alberta	35%	8.93%	9.50%	NEB reg'd, incentive agreement
B.C. System***	100.0%	200		Alb.-B.C. to B.C.-U.S. borders	36%	8.88%	9.03%	NEB regul., cost-of-service basis
GTN	100.0%	2,174	466	Near Kingsgate, British Columbia-Idaho border to near Malin, Oregon-California	35%	12.2%	12.2%	U.S. FERC, 95% capacity covered by long-term contracts, ten years average life. Transports 2.9 bcf/d (in service since 1992)
North Baja Pipeline	100.0%	128		Near Ehrenberg, Arizona to near Ogilby, California on California-Mexico border				
Foothills (Alb.-Sask.)***	100.0%	1,040	400	Caroline, Alta. to B.C.-U.S. border	36%	8.88%		NEB reg'd, cost-of-service basis
Foothills (Alb.-B.C.)***	100.0%		0	Caroline, Alta. to Sask.-U.S. border	36%	8.88%		NEB reg'd, cost-of-service basis
Total 100% Subs.		41,142	7,357					
Great Lakes Gas Transm.	50.0%	3,387	268	Emerson, Man. to Dawn, Ont.	44%	13.25%		U.S.-FERC approv. settlem't to 10/05
Iroquois Gas Transm.	44.5%	663	221	E. Ontario to Long Island, N.Y.	35%	12.38%		U.S.-FERC approv. settlem't to 01/04
Ventures LP	100.0%	148		Feeder pipeline to oil sands region	n/a	n/a		
Trans Québec & Maritimes	50.0%	572	167	Ont.-Qué. to Qué.-N.H. borders	30%	9.90%		NEB reg'd on cost-of-service basis
Northern Border* (1)	4.0%	2,010	1,404	Sask. through Iowa to Chicago, Ill.	35%	12.00%		U.S.-FERC approv. settlem't to 02/06
Tuscarora+ & Other	7.6%+		68	Malin, Oregon to Reno, Nevada	30%	13.00%		U.S.-FERC on ten-yr. contractual tolls
Portland Natural Gas Tran.	61.7%	471		Pittsburg, N.H. to Portland, Maine	30%	14.00%		U.S.-FERC recourse rate agreement
Bruce Power			254					
Joint Venture Affiliates*		5,241	978					
TCPL			2,589					
Total		46,383	10,924					

* Excluded from total kilometres.
**Debt allocation for holding company and 100%-owned subsidiaries for indicative purposes as holding company funds all financing requirements. Affiliate debt total includes Portland Natural Gas Transmission loans only. ***Deemed equity increased to 36% from 30% for 2006.
(1) Indirect 50% ownership interest in General partnership through TC PipeLines, LP. n/a = not applicable.

I. Gas Transmission – Pipelines

(1) Gas Transmission [75% of 2005 of net income before extraordinary items and Corporate (NIBE), 17% of capex (40% in 2004)].

- One of the largest pipeline companies in North America with 41,000 kilometres (25,600 miles) of natural gas pipeline provided through four main wholly owned systems.
- Extensive experience in operating large diameter, cold weather pipelines with a track record of completing large pipeline projects within budget.

Major Pipeline Systems:

Alberta System (18% of NIBE):

- Dominates the intra-Alberta market, and gathers natural gas for use within the province and delivers gas to connecting systems at Alberta's border for export to eastern Canada and the United States (see separate NOVA Gas Transmission Ltd. report).

Canadian Mainline (34% of NIBE):

- Dominates the Canadian export pipeline system together with Northern Border.
- Extends from the Alberta/Saskatchewan border, connecting with the Alberta System, east to the Québec/Vermont border, and connecting with other natural gas pipelines in Canada and the United States

GTN (9% of 2005 NIBE):

A 2,174 kilometre (1,350 mile), 2.9 bcf/d capacity mainline pipeline system, one of the largest transporters of WCSB natural gas into the United States, from the British Columbia-Idaho border, to the Oregon-California border serving markets in the U.S. Pacific Northwest, Nevada, and California.

- Contracts: Approximately 88% of capacity covered by long-term contracts with an average life of ten years. Common set of customers to TCPL's B.C. System.

North Baja Pipeline System (Baja):

The natural gas transported comes primarily from the southwestern United States to markets in northern Baja, California, and Mexico, in service since September 2002.

- 100% of capacity of 0.5 bcf/d covered by 20-year contracts. Connects to Sempra Energy's Mexican pipeline. Sempra's affiliated companies are major long-term customers.

(2) Joint Ventures in Pipeline Projects (12% of 2005 NIBE): See above table for details. Interest held through TCPL. A portion of its interest in TC Pipelines, LP was sold in Q1 2005.

- Subject to regulation by either federal or provincial/state regulators.

II. Power – Nominal Generating Capacity in MW

	Nominal Generating Capacity in Megawatts (MW)			
Eastern Operations	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003*	Fuel Type
Ocean State	560	560	560	Natural gas
Curtis Palmer (sold in April 2004)	0	0	60	Hydro
Becancour (under construction)	550	550	550	Natural gas
Cartier Wind (under construction)	458	458		Wind
TC Hydro (previously USGen acquired in April 2005)	567	518		Hydro
Grandview (20-year contract with Irving)	90			Natural gas
	2,225	2,086	1,170	
Western Operations				
Sheerness	756			Coal
Sundance "A" - PPA (acquired in Aug. 2001)	560	560	560	Coal
Sundance "B" - PPA (50%-acquired in Dec. 2001)	353	353	353	Coal
ManChief (sold in April 2004)	0	0	300	Natural gas
MacKay River	165	165	165	Natural gas
Carseland	80	80	80	Natural gas
Bear Creek	80	80	80	Natural gas
Redwater	40	40	40	Natural gas
Cancarb Power Plant	27	27	27	Natural gas
	2,061	1,305	1,605	
Bruce Power L.P.* (31.6%/47.9% interest in B/A, acq. in Feb. 2003)				
Bruce A	2,450	1,000	1,000	Nuclear
Power LP (30.6% -sold in 2005)	0	228	328	Gas/waste heat/] Wood waste]
Total Nominal Generating Capacity	6,736	4,619	4,103	

*Updated capacity on restart of two units.

Energy

25% of NIBE, estimated 83% capex in 2005 (51% in 2004): Previously designated as Power, which now also includes natural gas storage and LNG.

Power 15% of NIBE, estimated 46% capex in 2005 (51% in 2004):
Largest supplier of power in Alberta, and provider for 20% of the Ontario market through Bruce Power.

- Focus on low-cost base load co-generation, using excess heat captured from natural gas-fired electricity production to generate a second source of energy.
- The bulk of capacity is covered by long-term fixed price supply contracts, including Bruce Power, following the OPA arrangements in 2005, covering all unit output.
- Involved in construction, ownership, operation, and management of power plants and marketing of electricity in western and eastern Canada, and the northeastern United States.
- Operates or manages 19 power plants, with Becancour under construction with completion expected in 2006.
- Acquired power generating assets from USGen in April 2005 for purchase price of US$505 million with benefit of storage and peaking capacity, and at year-end the Sheerness Power Purchase Arrangements similar to Sundance A and B.

Major developments:

I.a. Keystone crude pipeline project: Preliminary proposal to construct a US$2.1 billion, 3,000-kilometre crude oil pipeline to transport approximately 435,000 b/d of heavy crude oil from Hardisty, Alberta, to Wood River/Pakota, Illinois, including the conversion of 860 kilometre (530 miles) of one of the lines in TCPL's gas pipeline systems for oil transportation.

- Close to 80% contracted long-term, including commitments by ConocoPhillips with an option to obtain a 50% interest in the pipeline.

b. Tamazunchale pipeline project – Mexico:
US$181 million contract with the Comision Federal de Electricdad (CFE) to construct, own, and operate a 36 inch, 125 kilometre pipeline in east central Mexico:
To transport initially 170 mmcf/d of gas with in-service in December 2006 under a 26-year contract from Pemex facilities near Naranjos, Veracruz, to CFE power plants near Tamazunchale, San Luis Potosi.

c. Mackenzie Delta pipeline project:

- Reached agreement with the Mackenzie Delta Producers and Aboriginal Pipeline Group to become a full participant of the proposed Mackenzie Delta project.
- TCPL gained an option to acquire a 5% ownership interest in the proposed pipeline and first right of refusal to acquire 50% of equity disposed by producers and an one-third interest in any expansions.
- To construct 1,220 kilometres of 30-inch pipeline to transport northern gas to the Canadian and U.S. markets, from Inuvik, Northwest Territories, to the northern border of Alberta to connect with the Alberta System.
- Application filed October 7, 2004. Regulatory delays and aboriginal issues likely will delay the project with in-service being pushed to early in the next decade.
- Economics of the project are under review by the sponsorship group spearheaded by Imperial Oil Limited.

d. Alaska Pipeline project: Application under the *Stranded Gas Development Act* filed in June 2004, with in-service expected mid next decade.

- The U.S. Senate approved US$18 billion in loan guarantees to support the project.

II. Power projects:
a. Agreement to build, own, and operate a $500 million, 550 MW gas-fired plant in Becancour, Québec, in-service late 2006 supported by a long-term supply contract with Hydro-Québec.
b.Cartier Wind Energy Inc. (50%-owned subsidiary) awarded six projects to build 740 MW of wind energy facilities in the Gaspe region of Québec for an estimated $1.1 billion between 2006 and 2012. Supported by long-term supply contract with Hydro-Québec
c. Bruce Restart (47.9% interest, $2.13 billion estimated cost): Restart of Bruce A Units 1 and 2 (1,500 MW). Supported by OPA long-term contracts, providing price support and capital costs sharing for overruns. OPA also commits to fixed price/floor price contracts on the existing Bruce A and B units, respectively.

III. LNG: Prolonged approval process commenced to jointly pursue the following:

- With Petro-Canada, an LNG facility in Gros Cacouna, Québec, northeast of Montréal. Proposed capacity: 500 million cubic feet (mmcf/d) at an estimated cost of $660 million in-service in 2010.
- Broadwater Energy LLC LNG project: With Shell US Gas & Power LLC, to develop an onshore LNG regasification terminal in Long Island Sound, New York State. Proposed capacity of one bcf/d at an estimated cost of at least US$700 billion, in-service in late 2010.

TransCanada PipeLines Limited

(Proportional Consolidation)

Balance Sheet

($ millions)	June 30	December 31	December 31		June 30	December 3	December 31
Assets	2006	2005	2004	**Liabilities & Equity**	2006	2005	2004
Cash & equivalents	314	212	187	Short-term debt	509	962	546
Accounts receivable	741	796	627	A/P & accrued liab.	1,476	1,716	1,429
Inventories	249	281	174	L.t.d. due in one year	449	434	849
Other	205	277	120	**Current Liabilities**	2,434	3,112	2,824
Unrealized trading gains	0	0	0	Long-term debt - recourse	10,411	9,640	9,713
Current assets of disc. ops.	0	0	0	Long-term debt - non-recourse	1,157	937	779
Current Assets	1,509	1,566	1,108	Jr. sub. debs (TOPrS)	0	0	19
Unrealized trading gains	0	0	0	Pref. securities (COPrS)	513	536	670
Long-term investments	74	400	840	Pref. shares	389	389	389
Property, plant & equip.	20,778	20,038	18,704	Def. inc. taxes	691	703	509
Other assets	2,205	2,109	1,477	Deferred liabilities	1,245	1,590	742
				Common equity	7,726	7,206	6,484
Total	24,566	24,113	22,129	**Total**	24,566	24,113	22,129

Balance Sheet &	6 months	6 months	Roling 12 mos.	For the year ended December 31				
Liquidity Ratios (1)	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002	2001
Current ratio	0.62	0.50	0.62	0.50	0.39	0.52	0.56	0.60
Total debt in capital structure*	62.2%	63.9%	62.2%	61.9%	64.1%	64.2%	65.2%	67.5%
Net debt in capital structure*	61.7%	62.7%	61.7%	61.5%	63.7%	63.5%	64.8%	66.9%
Common equity in capital structure	35.6%	33.7%	35.6%	35.8%	33.3%	33.0%	32.0%	29.8%
Deemed equity: Mainline	36.0%	36.0%	36.0%	36.0%	36.0%	33.0%	33.0%	30.0%
Cash flow/total debt* (times)	0.17	0.16	0.16	0.00	0.13	0.15	0.16	0.12
(Cash flow-divs.)/net capex (2)	1.22	4.62	2.38	14.67	13.77	3.15	2.15	2.28
Common dividend payout (bef. extras.)	71.7%	78.1%	75.6%	78.7%	79.5%	67.4%	67.1%	65.0%
Coverage Ratios (3)								
EBIT interest coverage (times)	2.53	2.25	2.46	2.32	2.35	2.32	2.29	2.14
EBITDA interest coverage (times)	3.68	3.37	3.60	3.45	3.43	3.34	3.18	2.92
Fixed-charges coverage (times)	2.26	1.99	2.17	2.03	2.15	2.10	2.08	1.93
Profitability Ratios								
Operating margin	31.0%	34.5%	31.6%	33.3%	38.8%	38.3%	41.5%	40.5%
Profit margin	12.9%	14.4%	12.1%	15.1%	16.4%	15.6%	15.0%	13.8%
Transmission profit margin	14.0%	16.1%	0.0%	15.3%	14.8%	16.0%	16.7%	15.1%
Power profit margin	10.7%	8.4%	12.7%	10.4%	17.6%	14.7%	11.3%	12.0%
Return on common equity (bef. extras.)	11.6%	11.3%	12.7%	12.3%	12.5%	13.1%	12.8%	24.2%
Allowed ROE - Mainline	8.88%	9.46%	n.a.	9.46%	9.56%	9.79%	9.53%	9.61%
Return on capital	7.4%	7.2%	7.8%	7.7%	7.5%	7.7%	7.5%	14.5%
Segmented Earnings ($ millions)								
Transmission	273	320	588	635	579	633	653	585
Power	174	73	305	204	209	201	146	168
Gas marketing	n/a	n/a	0%	n/a	n/a	n/a	n/a	n/a
Corporate and other	14	15	83	84	49	(3)	(27)	(28)
Net income before extras. (bef. pfd.)	461	408	976	923	837	831	772	725
Reported earnings (bef. pfd.; incl. disc. ops.)	553	470	1,376	1,293	1,083	911	805	653
Cash Flow								
Cash flow from operations	1,083	978	2,067	1,962	1,585	1,810	1,827	1,497
Dividends and pref. sec. charges	(305)	(289)	(676)	(660)	(623)	(588)	(546)	(517)
Capital expenditures	(630)	(243)	(1,141)	(754)	(476)	(391)	(599)	(440)
Acquisitions, net	(358)	(632)	(1,043)	(1,317)	(1,516)	(570)	(228)	(475)
Gross free cash flow	(210)	(186)	(793)	(769)	(1,030)	261	454	65
Changes in working capital items	(93)	(263)	121	(49)	34	112	33	170
Disposals & other	7	152	590	735	386	(190)	(115)	1,200
Net free cash flow	(296)	(297)	(82)	(83)	(610)	183	372	1,435
Operating Statistics								
Average rate base: Mainline ($ millions)	7,454	7,873	n.a.	7,807	8,196	8,565	8,884	9,255
Average rate base: Alberta System ($ millions)	4,305	4,534	n.a.	4,446	4,619	4,878	5,074	5,266
Km of pipeline: Mainline + Alberta System				0	37,600	37,600	37,600	37,400
Volume shipments: Mainline (bcf)	1,144	1,044	n.a.	2,997	2,621	2,628	2,630	2,450
Volume shipments: Alberta System (bcf)	2,070	1,979	n.a.	3,999	3,909	3,883	4,146	4,059
% exports to U.S. (Mainline)				53%	53%	53%	53%	50%

(1) DBRS allocates debt and equity equivalents to preferreds and minority interest. (2) Capital expenditures excluding acquisitions and capitalized interest.

(3) Excl. AFUDC, capitalized interest, debt amortizations, and equity earnings. * Includes joint venture non-recourse debt and portions of preferred securities/shares.

n.a. = not available.

DBRS Rating Report
Terasen Inc.

Terasen Inc.

Report Date: September 11, 2006
Press Release: September 11, 2006
Previous Report: June 21, 2004

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Rating

Rating	Trend	Rating Action	Debt Rated
BBB (high)	--	Under Review – Negative	Medium-Term Note Debentures
BBB	--	Under Review – Negative	Unsecured Subordinated Debentures
R-2 (high)	--	Under Review – Negative	Commercial Paper

Rating History

	Current	2005	2004	2003	2002	2001	2000
Medium-Term Note Debentures	BBB (high)	BBB (high)	A (low)	A (low)	A (low)	A (low)	NR
Unsecured Subordinated Debentures	BBB	BBB	BBB (high)y	BBB (high)y	BBB (high)y	BBB (high)y	NR
Commercial Paper	R-2 (high)	R-2 (high)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Rating Update

The ratings of Terasen Inc. (Terasen or the Company) as outlined above and those of its parent, Kinder Morgan, Inc., (KMI) remain Under Review with Negative Implications where they were placed on May 30, 2006, after the proposed management buyout (MBO) of KMI for US$22 billion. The transaction is expected to close by early 2007, subject to regulatory approvals. The negative implications reflect the following: (1) Uncertainties surrounding the newly private company's financial policies. (2) Potential impact on Terasen, should increased dividends be required to support KMI's high debt load. (3) Ownership by a lower rated entity, particularly if KMI is downgraded (currently rated BBB, Under Review – Negative) on consummation of the mostly debt funded (67%) MBO. (4) To a lesser extent, Terasen's substantial development projects, estimated at $3.1 billion to 2010, which could entail execution and financial risks. In December 2005, the ratings of Terasen were downgraded for similar reasons, following its $5.9 billion leveraged buyout by KMI (80% debt funded). Presently, Terasen's financial profile remains unchanged as the debt used to acquire Terasen was financed at an intermediate holding company with a KMI guarantee, and no dividends have been made to KMI.

Terasen's consolidated operations remain stable, underpinned by its regulated businesses in crude oil pipelines in the growing oil sands regions in western Canada, and a strong gas distribution franchise in British Columbia. Most revenues are covered on a cost-of-recovery basis with incentive sharing, or by long-term contracts, ensuring stability of cash flow. Future prospects are driven by substantial pipeline projects to 2010 and beyond, which would see capacity doubling at its two main pipelines. DBRS expects most of the development projects to be supported by long-term commitments. The intended transfer of Terasen Pipelines (Trans Mountain) Inc. (TM) to Kinder Morgan Energy Partners, L.P. (KMP), a major operated affiliate of KMI, on its MBO closing would reduce capex considerably. Timing of expansions at Terasen Pipelines (Corridor) Inc. (Corridor) is tied to the economics of the oil sands expansion project sponsored by Shell Canada Limited, currently under review due to cost pressures. (Continued on page 2.)

Rating Considerations

Strengths

- Non-consolidated and consolidated financial metrics remain reasonable, and modest holdco debt
- Increased diversification provides greater stability to dividend income and operating cash flows
- Majority of assets are rate regulated
- Substantial growth projects in the regulated segments

Challenges

- Financial and business risk associated with purchase by KMI and pending the KMI MBO
- Significant financing requirements for growth projects
- Gas distribution operations sensitive to changes in interest rates through allowed ROE

Financial Information

	6 months	6 months	Rolling 12 mos.	For the year ended December 31			
Consolidated Basis	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
Net income before extra. items/prefs. ($ millions)	89.2	94.0	151.5	156.2	155.3	139.4	116.6
Operating cash flow ($ millions)	140.0	159.9	278.6	298.5	295.2	289.3	232.4
Return on average common equity	12.2%	12.9%	10.9%	11.7%	11.1%	10.4%	11.2%
% adj. debt in capital structure (1)	65.0%	67.9%	65.0%	69.2%	66.0%	67.6%	66.8%
Cash flow/total adj. debt (1)	0.10	0.11	0.10	0.10	0.10	0.10	0.09
% adj. debt in capital structure - **unconsolidated** (1)	n.a.	n.a.	n.a.	35.5%	32.5%	28.1%	17.9%
Cash flow/total adj. debt - **unconsolidated** (times) (1)	n.a.	n.a.	n.a.	0.13	0.09	0.29	0.29
Fixed-charges coverage (times)	2.23	2.24	2.06	2.06	2.12	1.88	1.79
Gas distribution throughputs (bcf) (2)	n.a.	n.a.	n.a.	176.9	172.9	187.3	187.3
Oil pipeline throughputs (thousands bbl/day) - TM	227.7	206.2	n.a.	220.9	236.1	201.2	201.2
Dividend income from subs. ($ millions)	-	-	-	104.8	73.8	176.1	92.7

(1) Capital securities of $125 million treated as debt by DBRS. (2) Incl. sales and transportation volumes only. n.a. = not available.

The Company

Terasen is a holding company that wholly owns the following: (1) Natural gas distribution mainly through Terasen Gas Inc. (2) Crude oil pipelines through TM (from Alberta into British Columbia and the U.S. Northwest), and Corridor (to transport diluted bitumen within Alberta). Terasen also has a one-third interest in Express/Platte Pipeline System (Express) (from Alberta to the U.S. Midwest).

Authorized Commercial Paper Amount

Limited to $300 million.

Notes: All figures are in Canadian dollars unless otherwise noted.
The Unsecured Subordinated Debentures contain certain unique covenants that give them equity-like characteristics.

RATING UPDATE (Continued from page 1.)

On an unconsolidated basis, dividend earnings should be more than sufficient to cover Terasen's modest debt and other obligations, with gas distribution as a steady contributor (40% to 45% of earnings), and increasing importance of Express Pipeline due to recent expansions. Contributions from TM, accounting for about 33% of earnings in the past five years, however, could be limited in the medium term as cash flow is deployed for project developments to 2010. TM will likely access the public debt market for funding, after its full exit in 2005, barring the transfer to KMP.

In order to maintain its current financial standing, Terasen's key challenge is to manage the funding mix for its largest-ever growth projects, without overleveraging, or assuming undue construction risks. Appropriate funding of its equity portion is important. This could reach the $750 million to $900 million level based on a 25% to 30% equity component attached to other new pipeline projects in Canada. Financing could effectively be undertaken at the KMI level as in the case of the Terasen acquisition with no direct impact on Terasen, or through other arrangements, such as asset monetization.

RATING APPROACH

(1) The rating of Terasen is based on the strength of the non-consolidated balance sheet and cash flows, the diverse business mix with good geographic spread on a consolidated basis, and the creditworthiness of the following wholly owned operating subsidiaries (see separate reports):

- Terasen Gas Inc. (Terasen Gas) – R-1 (low) and A
- TM – rated A (low) prior to rating discontinuation in late 2005 on full repayment of public debt
- Corridor – (R-1 (low) and A)
- Terasen Gas (Vancouver Island) Inc. (TGVI) – not rated

Other investments: primarily Express (33% interest) – A (low)

(2) The rating of Terasen also reflects its status as a holdco and the potential impact of its ownership by KMI.

Capital Projects

Projects, 2006-2010	Capacity	Projected Cost ($ million)	Completion Period	Comments
Trans Mountain Expansion				
-Pump station expansion	35kbd	230	Q2 2007	] Both covered by Incentive Tolling Settlement with shippers. Loop project with
-Anchor Loop	45kbd	365	2008	] NEB filing in early 2006 for approval expected by year end.
-TMX 2	100kbd	900	2010	Loop between Valemont and Kamloops in B.C. and back to Edmonton. Open season for prospective shippers in progress.
Corridor expansion*	200kbd	1,600	TBD	Diluent/bitumen pipeline from Muskeg River Mine to Edmonton region.
		3,095		Tied to expansion plans for AOSP under review.
Potential Projects				
TMX3	300kbd	900	2011	Loop between Kamloops and Lower Mainland.
TMX North	400kbd	2,000	TBD	Northern line between Valemont & Kitimat, British Columbia.

*Revised from previous estimate of $1.0 billion.

- Growth projects totalling $2.5 billion are in different stages of development, except the Corridor expansion, which is driven by the Athabasca Oil Sands Project (AOSP) currently under review by its contracted shippers, Shell Canada Limited (60% interest), Chevron Canada Resources Limited (20%) and Western Oil Sands Inc. (20%).

RATING CONSIDERATIONS

Strengths

(1) Terasen's financial profile remains reasonable, both on a non-consolidated and consolidated basis, given the regulated nature of its relatively low risk and stable business. Non-consolidated adjusted debt-to-capital was at 36% with fixed charge coverage at 3.3 times in 2005. Cash flow-to-debt at 0.13 times (close to 0.30 times prior to 2004) was adversely affected by debt repayments at TM, limiting dividend distributions in 2005 (also in 2004). Dividend earnings are more than adequate to service Terasen's modest debt load. Consolidated metrics are in line with the deemed capital structure approved by the regulators.

(2) The various acquisitions and investments made by Terasen over the past few years have significantly increased the diversification of its asset base and earnings, thus increasing the stability in its dividend income and operating cash flows. While Terasen Gas has always been a significant and stable contributor of dividends (average of 45% in the past five years), the dividend flow from TM, Terasen's second-largest subsidiary, has been significant (33%), but has been much more volatile during periods of debt repayments (all debt was repaid in 2005).

(3) Virtually all of Terasen's asset base is rate regulated, which provides a high degree of long-term stability to Terasen's consolidated balance sheet, earnings, and cash flows.

(4) Future prospects are driven by substantial growth projects to 2010, predominantly in pipeline developments, which in most instances would be supported by long-term commitments, ensuring continued stability.

Challenges

(1) The pending KMI MBO presents both business and financial risks for Terasen. There are uncertainties surrounding the newly private company's financing strategies and potentially higher dividend payments required of Terasen to help service its parent's higher debt load. MBO debt of $7.5 billion could be added to $2.1 billion of Terasen acquisition debt, resulting in debt-to-capital estimated at 67% on a pro forma basis with minimal cash flow protection, at least in the initial years when capital spending is high.
(2) Significant financing requirements associated with Terasen's largest-ever capital projects could strain the balance sheet, particularly in a highly competitive environment in western Canada.
(3) The Company's gas distribution earnings and cash flows are sensitive to changes in long-term interest rates through allowed ROEs. The low interest rate environment over the past years has resulted in low allowed ROEs for Terasen Gas (8.29% in 2006 versus 9.03% in 2005). Further, it is increasingly difficult to achieve productivity improvements and efficiencies under the new rate plan. However, the adverse impact of these factors on performance should be partly offset by Terasen Gas' relatively low cost base and growing customer base in a strong market.

EARNINGS AND OUTLOOK

Earnings Section

Income Statement (Consolidated)	6 months	6 months	Rolling 12 mos.	For the year ended December 31			
($ millions)	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
Net revenues	458.8	454.0	893.6	888.8	897.3	854.5	807.5
EBITDA	271.3	269.8	516.8	515.3	524.3	499.8	452.1
Depreciation and amortization	72.6	70.7	144.5	142.6	147.1	133.4	110.7
EBIT	198.7	199.1	372.3	372.7	377.2	366.4	341.4
Net interest expense	89.1	88.8	180.8	180.5	167.7	176.0	160.8
Pre-tax income	109.6	110.3	191.5	192.2	209.5	190.4	180.6
Net Income (before extras. and pfd.)	89.2	94.0	151.5	156.2	155.3	139.4	116.6
Return on average common equity (bef. extras.)	12.2%	12.9%	10.9%	11.7%	11.1%	10.4%	11.2%

Segmented Earnings (Consolidated)	6 months	6 months	Rolling 12 mos.	For the year ended December 31			
($ millions)	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
EBIT							
Gas distribution				284.4	272.4	277.7	276.7
Petroleum transportation	not available on interim basis			83.3	101.1	92.0	56.4
Other				(33.0)	(2.7)	(3.3)	3.4
Corporate adjustment for non-recurring items BT				38.0	6.4	-	4.9
Total EBIT	198.7	199.1	372.3	372.7	377.2	366.4	341.4
Net Income							
Gas distribution	40.6	63.4	78.0	100.8	95.9	95.4	92.4
Petroleum transportation	34.2	33.6	72.2	71.6	70.9	56.2	29.3
Other	0.5	(13.7)	(35.0)	(49.2)	(20.3)	(12.2)	(9.2)
Corporate adjustment for non-recurring items AT	13.9	10.7	36.3	33.0	8.8	-	4.1
Net Income (before extras.)	89.2	94.0	151.5	156.2	155.3	139.4	116.6
Extraordinary/unusual items	(26.5)	1.8	(83.4)	(55.0)	-	-	(4.1)
Preferred dividends/capital sec. dist'n	-	-	-	-	6.6	6.7	6.7
Net income (available to common)	62.7	95.8	68.1	101.2	148.7	132.7	105.8

Summary

2005 Consolidated Basis:

- Terasen continued to record stable performance as net income before extraordinary items rose marginally to $156 million. Higher earnings from gas distribution due to the strong housing market in British Columbia and expansion at Express were more than offset by lower earnings and throughput at TM caused by temporary production outages due to the Suncor fire and refinery turnarounds at Syncrude (strong activities resumed in 2006).
- Net income of $101 million (down 32%) was affected by non-recurring charges, totalling $55 million, primarily related to the acquisition by KMI in late 2005 and redemption premium on retiring TM's remaining debt of $35 million debentures.

6 months to June 30, 2006 (Q2 2006):

Lower net earnings before extraordinary items (-5%) were primarily affected by the lower allowed ROE (8.80% versus 9.03% in Q2 2005) for gas distribution, despite the higher deemed equity thickness.

Outlook

Consolidated Basis:

Incremental rise in earnings is likely supported by growth projects as outlined under the Capital Projects section. The key driver is the TM staged expansions expected to be in service in Q2 2007 and year-end 2008, increasing capacity by 33% to accommodate the rising oil sands demand.

- Over the medium term, incremental earnings growth is expected. Near term, the anticipated growth in pipeline capacity coupled with higher deemed equity thickness at gas distribution (to 35% and 40% for Terasen Gas and TGVI from 33% and 35%, respectively) and amended ROE formula with slightly higher risk premium will likely offset the negative earnings impact of Terasen Gas' low allowed ROE (8.29% vs. 9.03% in 2005).

- Longer term prospects are dependent on the large scale TMX2 with open season in progress to secure potential long-term commitments and TMX North, and Corridor expansions under review by its contracted shippers.

Non-Consolidated Basis:

- Net income through dividend distributions could be limited due to expansions at TM and Corridor. The adverse impact should be partly mitigated by stable distributions from gas distribution supplemented by distributions from Express.

Financial Profile

Consolidated Basis	6 months	6 months	Rolling 12 mos.	For the year ended December 31			
($ millions)	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002
EBITDA	72.6	70.7	144.5	142.6	147.1	133.4	110.7
Net income (bef. extras., after prefs.)	89.2	94.0	151.5	156.2	148.7	132.7	109.9
Depreciation & amortization	72.6	73.2	142.0	142.6	147.1	133.4	110.7
Non-cash adjustments	(21.8)	(7.3)	(14.8)	(0.3)	(0.6)	23.2	11.8
Operating Cash Flow	140.0	159.9	278.6	298.5	295.2	289.3	232.4
Capital expenditures	(110.1)	(126.9)	(197.9)	(214.7)	(154.4)	(222.9)	(395.7)
Common dividends	0.0	(47.4)	(47.7)	(95.1)	(93.0)	(86.1)	(59.8)
Gross Free Cash Flow	29.9	(14.4)	33.0	(11.3)	47.8	(19.7)	(223.1)
Changes in working capital & rate stabilization acc't	148.6	17.8	77.8	(53.0)	45.7	(19.5)	74.1
Net Free Cash Flow	178.5	3.4	110.8	(64.3)	93.5	(39.2)	(149.0)
Net investments	122.6	(2.9)	164.5	39.0	52.1	(2.3)	(315.2)
Net debt financing	(335.3)	65.5	(251.2)	149.6	(85.0)	234.5	(11.9)
Net capital securities financing	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net equity financing/other	4.6	5.6	21.0	22.0	14.7	10.1	474.2
Net change in cash	(29.6)	71.6	45.1	146.3	75.3	203.1	(1.9)
Total debt	2,762	3,019	2,762	3,093	2,831	2,907	2,672
% adj. debt in capital structure (1)	65.0%	67.9%	65.0%	69.2%	66.0%	67.6%	66.8%
Cash flow/total adj. debt (times) (1)	0.10	0.11	0.10	0.10	0.10	0.10	0.09
Fixed-charges coverage (times)	2.23	2.24	2.06	2.06	2.12	1.88	1.79
% debt in capital structure - **unconsolidated**	n.a.	n.a.	n.a.	35.5%	0	28.1%	17.9%
Cash flow/total adj. debt (times) -**unconsolidated** (1)	n.a.	n.a.	n.a.	0.13	n.a.	0.29	0.29

(1) The $125 million capital securities are treated as debt DBRS. n.a. = not available.

Summary

Net free cash flow improved in Q2 2006 with the completion of the Express expansion in 2005, resulting in lower capital expenditures. There was no dividend distribution to KMI with surplus funds from operations and the sale of the water and utilities business primarily used to retire $100 million of maturing bonds at Terasen.

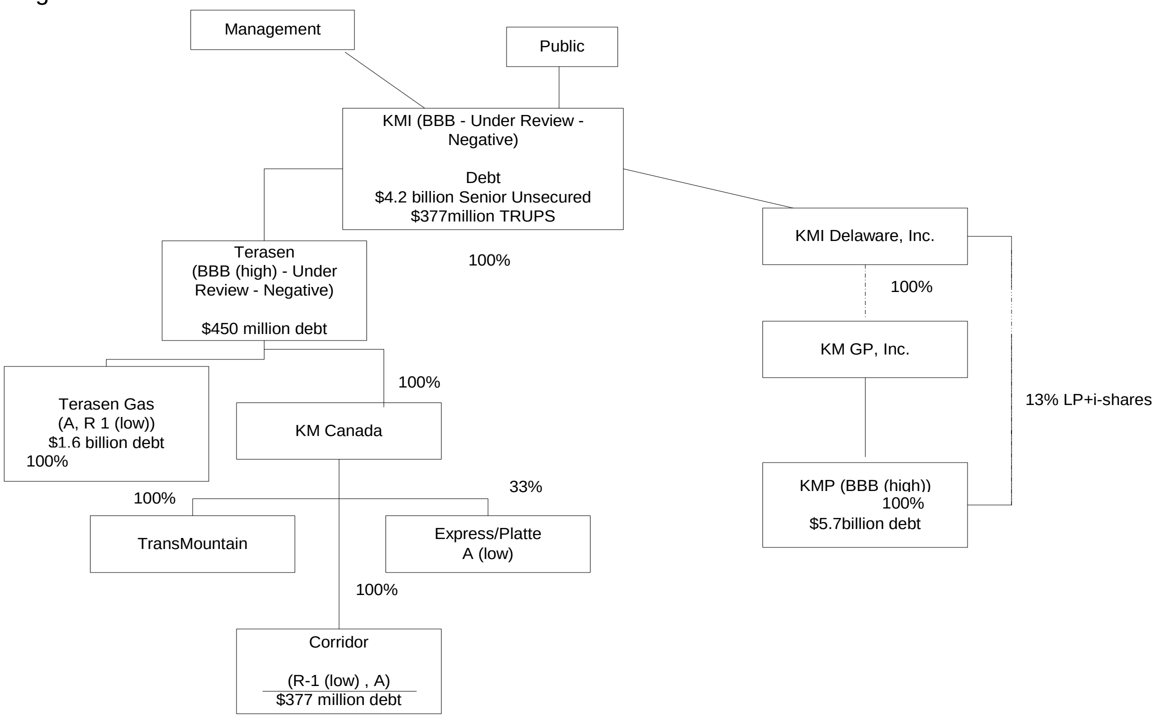
- As a result, key financial metrics on a consolidated basis improved, particularly cash flow-to-debt (as debt level has stablized at the $3 billion level) and fixed charge coverage.
- On an unconsolidated basis, debt-to-capital remained acceptable at 35% in 2005, although increased from previous years. Cash flow/debt coverage was low at 0.13 times versus 0.29 times in 2002 and 2003, mainly attributable to lower earnings at TM due to temporary production outages and refinery turnarounds (strong activities resumed in 2006). With a modest debt level at the holdco, Terasen can manage dividend distributions from the operating companies to service or repay its debt.

Outlook

- Operating cash flows should remain generally stable with a gradual rising trend from 2006 underpinned by the Express expansion (+60% capacity) in 2005, and $600 million of TM growth projects in progress on a cost-of-recovery basis. Further TM and Corridor expansions are currently under review.
- The trend for the Canadian regulators to raise the deemed equity thickness for utilities as seen in Terasen Gas and TGVI would enhance cash flow, even in a low interest rate environment.
- In order to maintain its current financial standing, one of Terasen's key challenges is to manage the funding mix for its largest-ever growth projects estimated at $3.1 billion (over three phases), without overleveraging, or assuming undue construction risks. Appropriate funding of the equity portion for these projects is important. This could reach the $750 million to $900 million level based on a 25% to 30% equity component attached to other new pipeline projects in Canada.

- Financing could be undertaken at the Terasen level, or through a special financing vehicle as in the case of KMI's acquisition bearing the latter's guarantee, with no direct impact on Terasen's balance sheet. Alternative financing could include asset monetization.
- Should the MBO proceed, KMI intends to transfer TM to KMP, a 13% affiliate which it manages, to lighten the looming financing requirements (over 60% reduction estimated). This would result in Terasen operating as a stable regulated business, although with much reduced growth prospects.

Organization Structure



- All major subsidiaries are self financing. Terasen's financing needs are mainly to meet the equity portion of any expansions or growth projects at its subsidiaries and to service its own debt obligations. DBRS considers the holdco debt as manageable, given its modest level and the diverse source of dividends for servicing.

BANK LINES

As at March 31, 2006, the Company had in place credit facilities totalling $1.565 billion (approximately $600 million utilized) including backup lines for commercial paper programs. Facilities for Terasen and its subsidiaries have been re-negotiated for a longer term with common financial covenants and events of default provisions.

(1) Terasen – $450 million three-year facility due May 2009.

(2) Terasen Gas – $500 million three-year facility due June 2009, extendible annually.
(3) Terasen Pipelines (Corridor) Inc. – $225 million 364-day revolving facility and $20 million 364-day non-revolver.
(4) TGVI – $350 million five-year facility due January 2011 and $20 million seven-year facility due January 2013.

Other Debt: $2.4 billion of notes and debentures at Terasen and its subsidiaries

Debt Maturities - Consolidated

As of December 31, 2005	2006*	2007	2008	2009	Beyond	Total
(US$ millions)	398	252	390	95	1,958	3,093
% total	13%	8%	13%	3%	63%	100%

*$100 million repaid in 2006.

- Terasen (non-consolidated) has only one $200 million maturity in 2008, which is manageable from a refinancing perspective with two $125 million notes due in 2014 and 2040, respectively.
- All subsidiaries, except TM, are self-financing. TM's only $35 million debt was repaid through Terasen in 2005, following the KMI acquisition. It is likely that the Company will re-institute a borrowing program at TM, should the company not be transferred to KMP as planned.

Description of Operations & Regulation

Terasen is a holding company whose principal operating subsidiaries are involved in regulated natural gas distribution and regulated oil pipeline businesses. The Company's operating businesses consist of the following (including loss-making water and utilities business sold in early 2006):

(1) Retail natural gas distribution (85% of EBIT)

Terasen Gas Inc. (wholly owned by Terasen)

- The largest natural gas distributor in British Columbia, serving approximately 892,000 customers or 95% of the province's natural gas users.
- Regulated by the British Columbia Utilities Commission (BCUC) and operates under a performance-based rate plan for the period from 2004 to 2007. Improved equity component (35% from 33%) and ROE formula was approved in March 2006.
- Key components of the plan include the following:
  - Operating and maintenance costs and base capital expenditures are subject to an incentive formula, reflecting increasing costs as a result of customer growth and inflation less a productivity factor equal to 50% of inflation during the first two years of the plan and 66% of inflation during the last two years of the plan.
  - 50/50 sharing with customers of earnings above or below the allowed ROE.
  - Ten year service quality measures designed to ensure the maintenance of service levels, as well as setting out the requirements for an annual review process.
  - Deferral accounts were established for insurance premiums and pension costs incurred by Terasen Gas, further increasing the longer term stability of earnings and cash flows.
- Allowed ROE is set annually according to the following formula:
  - 390 basis points (bp) above forecast long-term Government of Canada bond yield (from 350 bp over yield of 6% or lower).
  - The formula also provides for annual adjustments capturing 75% of the change in yields (from 80% of forecast yields higher than 6%).
- Deemed equity is 35% (from 33%) of total capital.

(2) Kinder Morgan Canada Inc. (25% of 2005 EBIT) operates through three crude oil pipeline systems.

a. Terasen Pipelines (Trans Mountain) Inc. (TM) (wholly owned by Terasen)

- Oil pipeline system (currently 1,260 kilometres with a sustainable capacity of 225,000 b/d) transporting crude oil and refined products from Alberta and northeastern British Columbia to the west coast, servicing refineries in Vancouver and Washington State.
  - TM also owns and operates Westridge Marine Terminal in Vancouver harbour, where crude oil is loaded aboard ocean-going vessels and aviation fuel is landed and stored.
- TM owns another pipeline (41 kilometres) that transports aviation fuel from the Westridge Marine Terminal and refineries and distribution terminals in the Burnaby area to the Vancouver International Airport.

Regulation: TM is regulated by three separate regulatory bodies: (1) The Canadian portion of the crude oil and refined product pipeline system by the National Energy Board (NEB). (2) The U.S. portion of the pipeline by Federal Energy Regulatory Commission (FERC) on a complaint basis. (3) The aviation turbine fuel pipeline by the BCUC.

- The Canadian portion of the pipeline system currently operates under a renewal incentive toll settlement, from 2006 to 2010.
  - Tolls are fixed for throughputs between 179,265 b/d and 201,280 bbl/d (28,500 and 32,000 cubic metres/day) and are not adjusted for inflation unless the Canadian inflation rate rises above 3.5%.
  - Shippers are responsible for revenue shortfall if average annual throughputs fall below 179,254 bbl/d; there is 50/50 sharing with shippers if average annual throughputs are above 201,280 bbl/d.
  - TM benefits 100% from operating and efficiency improvements.
  - 10.75% ROE on 45% equity (no change).

Expansions: TM is currently undertaking a pump station expansion and anchor loop project (estimated cost $665 million or $560 million equivalent) to raise capacity by 35,000 b/d and 40,000 b/d, respectively, to reach total capacity of 300,000 b/d by late 2008.

- Southern expansions through TMX-2 (estimated cost $1.3 billion) to raise capacity by 100,000 b/d for completion by 2010 is on the drawing board. TMX-3, for additional 300,000 b/d of capacity, is a potential project with major parameters to be determined.

b. Terasen Pipelines (Corridor) Inc. (Corridor) (wholly owned by Terasen)

- Corridor, operated by TM, owns a 493-kilometre (307-mile) diluted bitumen dual pipeline system that links two major components of the AOSP, the Muskeg River Mine (north of Fort McMurray) and the Scotford Upgrader in Fort Saskatchewan, Alberta, near Edmonton. It also connects the upgrader to refineries and pipeline terminals in the Edmonton area (including the Trans Mountain Pipeline), and provides storage facilities.
- The AOSP is jointly owned by Shell Canada Limited (60%), Chevron Canada Resources Limited (20%), and Western Oil Sands Inc. (20%), and Corridor is backed by long-term ship-or-pay contracts with these three entities on a pro-rata basis.
- Revenue requirements are governed by the associated contracts and are subject to regulation by the Alberta Energy and Utilities Board.

c. Express/Platte Pipeline System (one-third interest)

- The Express system consists of the Express Pipeline and the Platte Pipeline, transporting crude oil from Hardisty, Alberta, to the Wood River, Illinois, area.

Regulation: The Express system is regulated by three separate regulatory bodies: (1) The Canadian segment of the Express Pipeline is regulated by the National Energy Board (NEB). Most of its throughput capacity is contracted long-term with tolls determined thereunder. Tolls on uncommitted volumes are regulated by the NEB in Canada and by the FERC in the United States on a complaint basis only. (2) The Platte Pipeline has no contracts, and tolls are regulated by FERC on a complaint basis. (3) Petroleum transportation on the Platte Pipeline within the state of Wyoming is regulated by the Wyoming Public Service Commission, with tolls regulated on a similar basis to those of the NEB and the FERC.

Terasen Inc.

(Consolidated)

Balance Sheet

($ millions)	Jun. 30	For the year ended December 31			Jun. 30	For the year ended December 31	
Assets	2006	2005	2004	**Liabilities & Equity**	2006	2005	2004
Cash	37	79	20	Short-term debt	381	681	694
Accounts receivable	249	468	349	A/P + accrueds	458	537	434
Inventories	197	206	189	L.t.d. due in one year	134	398	417
Prepaids + other	82	97	38	**Current Liabilities**	973	1,617	1,545
Current Assets	565	851	596	Long-term debt	2,247	2,013	1,721
Net fixed assets	3,946	4,018	3,893	Def'd income taxes	82	89	69
Long-term rec. + investments	249	252	219	Other long-term liab.	175	182	141
Goodwill	76	76	128	Capital securities	0	125	125
Deferred charges	127	119	135	Shareholders' equity	1,487	1,291	1,371
Total	4,963	5,316	4,971	**Total**	4,963	5,316	4,971

Ratio Analysis	6 months	6 months	Rolling 12 mos.	For the year ended December 31				
Liquidity Ratios	June 30, 2006	June 30, 2005	June 30, 2006	2005	2004	2003	2002	2001
Current ratio	58.0%	44.8%	58.0%	52.6%	38.6%	39.0%	35.4%	39.9%
% debt in capital structure	65.0%	67.9%	65.0%	68.6%	65.4%	67.0%	66.2%	74.5%
% adj. debt in capital structure (1)	65.0%	67.9%	65.0%	69.2%	66.0%	67.6%	66.8%	75.3%
% debt in capital structure - **unconsolidated** (1)	n.a.	n.a.	n.a.	35.5%	32.5%	28.1%	17.9%	24.0%
Cash flow/total debt -**unconsolidated** (1)	n.a.	n.a.	n.a.	0.13	0.09	0.29	0.29	0.34
Cash flow/total debt	10.1%	10.6%	10.1%	9.7%	10.4%	10.0%	8.7%	7.7%
Cash flow/total adj.debt (1)	10.1%	10.6%	10.1%	9.6%	10.3%	9.9%	8.6%	7.6%
Adj. debt/EBITDA	5.09	5.59	5.34	6.05	5.45	5.87	5.97	6.36
Cash flow/capital expenditures	1.27	1.26	1.41	1.39	1.91	1.30	0.59	0.40
Cash flow/capex (Terasen Gas)	n.a.	n.a.	n.a.	1.00	1.61	1.27	1.34	0.98
Cash flow/capex (Trans Mountain)	n.a.	n.a.	n.a.	n.a.	2.23	n.m.	2.11	0.78
Cash flow-dividends/capex	1.27	0.89	1.17	0.95	1.31	0.91	0.44	0.30
Common dividend payout (before extras.)	0.0%	50.4%	31.5%	60.9%	62.5%	59.8%	54.4%	58.9%
Coverage Ratios								
EBIT interest coverage	2.23	2.24	2.06	2.06	2.25	1.98	1.90	1.80
EBITDA interest coverage	3.04	3.04	2.86	2.85	3.13	2.71	2.52	2.38
Fixed-charges coverage	2.23	2.24	2.06	2.06	2.12	1.88	1.79	1.69
EBIT interest coverage (unconsolidated)	n.a.	n.a.	n.a.	3.33	3.49	8.86	6.49	11.10
Fixed-charges coverage (unconsolidated)	n.a.	n.a.	n.a.	3.33	2.38	5.78	3.83	5.03
Profitability Ratios								
EBIT margin	20.1%	23.4%	20.5%	22.2%	25.2%	24.5%	24.3%	20.8%
EBIT margin, excludes cost of natural gas	43.3%	43.9%	41.7%	41.9%	42.0%	42.9%	42.3%	44.5%
Net margin (before extraordinary items)	19.5%	20.7%	16.9%	17.6%	17.3%	16.3%	14.4%	13.7%
Return on average common equity	12.2%	12.9%	10.9%	11.7%	11.1%	10.4%	11.2%	12.1%
Operating Efficiency and Statistics								
Throughputs – gas distribution (bcf) (2)	n.a.	n.a.	n.a.	176.9	172.9	187.3	187.3	164.7
- Oil pipeline (thousands bbl/day) (3)	227.7	206.2	n.a.	220.9	236.1	201.2	201.2	209.3
- U.S. deliveries (incl. in oil pipeline) (thousands bbl/day) (3)	95.2	59.6	n.a.	74.6	91.7	47.8	47.8	73.4
- Jet fuel (thousands bbl/day)						18.5	18.5	19.3
Approved ROE (Terasen Gas)	8.80%	9.03%	n.a.	9.03%	9.15%	9.42%	9.13%	9.25%

(1) The $125 million capital securities are treated as debt by DBRS.

(2) Throughputs include sales volumes and transportation volumes only.

(3) Throughput for Trans Mountain pipleines only. n.a. = not available.

DBRS Rating Report
Canadian Utilities Ltd.

Canadian Utilities Limited
Rating Report: January 31, 2007
Press Release: January 31, 2007
Previous Report: December 29, 2004

Canadian Utilities Limited

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Rating Table

Debt Rated	Rating Action	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures	A	Confirmed	Stable
Cumulative Preferred Shares	Pfd-2 (high)	Confirmed	Stable

Rating History

Debt Rated	Current	2006	2005	2004	2003
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures	A	A	A	A	A
Cumulative Preferred Shares	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)

RATING UPDATE

DBRS confirmed the ratings of Canadian Utilities Limited (CU or the Company) on October 30, 2006, as listed above. CU's consistent strong financial profile, both on a consolidated and non-consolidated basis, and stable business risk support the assigned ratings.

CU's regulated operations account for an estimated 55% to 60% of earnings, and continue to:
(1) generate strong and stable cash flows;
(2) benefit from a stable regulatory environment, despite slightly lower allowed ROEs for 2006, and

(3) contribute strong dividends to support CU's obligations. CU's non-regulated cash flows, primarily from natural gas midstream activities and non-regulated generation, have shown strength as the energy markets in which they operate have been on an upward trend.

On a consolidated basis, the leverage ratio remains reasonable at 54.6%, and allows CU to maintain very good financial flexibility. EBIT interest coverage and cash flow-to-debt ratios (12 months to September 2006) remain solid and consistent with current ratings at 3.2 times and 21%, respectively. On an estimated non-consolidated basis, CU's financial metrics remain very strong with cash flow-to-interest expense ratio at 44 times (DBRS estimate). Additionally, CU's credit profile is supported by:

(1) low debt at CU ($100 million), and
(2) CU's 51.9% shareholder (ATCO Ltd. (ATCO)) has cash requirements primarily limited to it's funding of common and preferred dividends. ATCO has no bonds/debentures outstanding and its cash needs are more than covered by CU's dividend.

Due to significant capital expenditure requirements, CUI's regulated utilities are expected to require financial support from CU over the next few years, which is likely to be in the form of reduced dividends. DBRS believes that CU's financing strategy is reasonable, and, barring any major changes, the current financial profile is expected to be maintained.
DBRS upgraded certain of CU's cumulative preferred shares on October 30, 2006 (see press release, and further details on page seven of this report). As a result, all of CU's cumulative preferred shares now carry a a Pfd-2 (high) rating.

RATING CONSIDERATIONS

Strengths

- Strong cash flow at regulated utilities
- Stable regulatory environment
- Strong financial profiles (consolidated and non-consolidated)
- Solid performance at non-regulated operations

Challenges

- Free cash flow deficits at regulated utilities
- Operational risk related to regulated generation
- Lower allowed ROEs
- Exposure to commodity price risk

RATING RATIONALE

The ratings of CU are supported by strong earnings and stable cash flows from CUI's regulated subsidiaries, which account for 55% to 60% of total earnings. Although CUI. will likely require financial support from CU (likely in the form of reduced dividends) over the medium term to partially finance its capital expenditure program, DBRS believes that CU has financial strength and liquidity to support its regulated subsidiaries without weakening its consolidated or non-consolidated credit metrics.

- While non-regulated operations (40% to 45% of earnings) have higher business risk, DBRS notes that they provide good earnings and cash flow diversity and with recent strong operations have contributed significantly to CU's performance.
- Debt levels at the holding company are low ($100 million outstanding) reflecting the Company's conservative strategy which results in no double-leverage of investments. Therefore, DBRS estimates cash flow-interest coverage to be 44 times, which is very strong.
- Liquidity at CU is strong, reflecting sizeable credit facilities and cash balances, while its
- short-term obligations and debt maturities are modest. CU can provide liquidity support to its non-regulated operations if required.
- ATCO, CU's 51.9% shareholder, maintains good access to the capital markets with a strong credit profile, no bonds/debentures outstanding, and a sizeable equity market capitalization.
- CU's fixed obligations are subordinate to the debt at CUI as well as to the non-recourse debt at generating projects.
- The Company benefits from the strong cash flows currently earned from midstream operations and from dividends received from CUI and its other generating projects which contribute to strong holding company's coverage.

THE COMPANY

CU is a holding company whose principal operating subsidiaries include the following:
(1) Through CU Inc. (CUI), regulated electric and gas transmission and distribution utilities, and electricity generation assets in Alberta that are subject to legislatively mandated long-term power purchase arrangements. (2) Midstream, project management, technology and information systems operations. (3) Non-regulated generation assets in Canada, the United Kingdom and Australia.

FINANCIAL INFORMATION

Consolidated Basis	12 mos. ended	For the year ended December 31				
($millions)	Sep. 2006	2005	2004	2003	2002	2001
EBIT	696	650	612	605	561	575
Gross free cash flow	7	(9)	(81)	(51)	(148)	(313)
Total debt in capital structure (1)	54.6%	54.8%	56.1%	55.0%	58.1%	59.5%
Cash flow / total debt (1)	21.0%	19.0%	16.5%	18.0%	16.8%	18.2%
Fixed-charges coverage (times)	2.72	2.54	2.38	2.41	2.46	2.58
EBIT coverage (times)	3.16	3.09	2.92	2.90	2.71	2.74
Dividend payout ratio	56.0%	52.6%	52.9%	49.9%	52.3%	50.2%

(1) Total debt adjusted for preferred shares and operating leases.

Authorized Commercial Paper Limit $200 Million

RATING CONSIDERATIONS

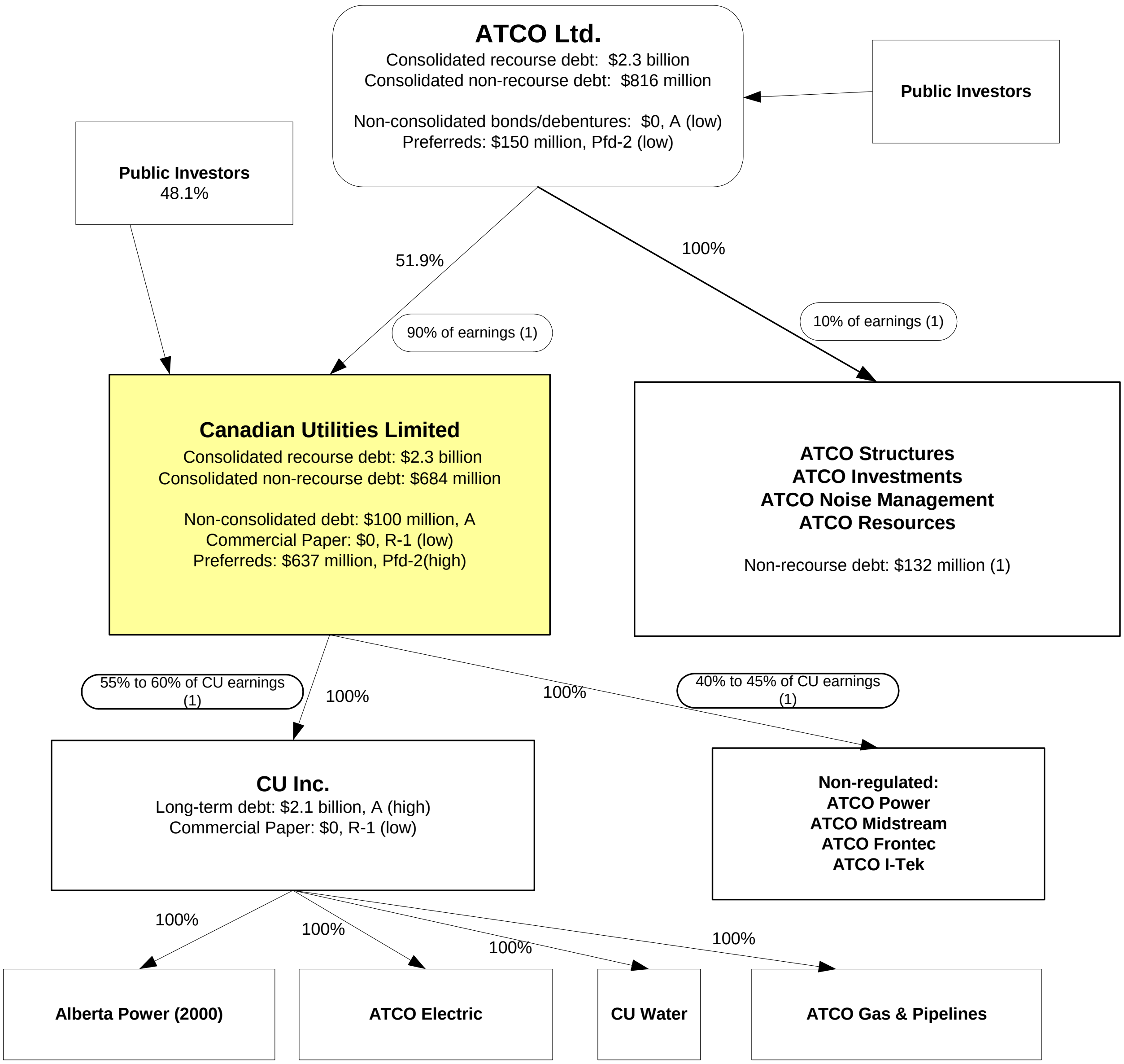
Strengths

- Strong cash flows from a portfolio of operations, including stable and lower risk regulated utilities, non-regulated generation, and gas storage and gas processing services.
- Regulated utilities benefit from a stable regulatory environment with acceptable allowed returns on investments.
- The non-regulated generation portfolio benefits from long-term power contracts (70% of total capacity) and improved market conditions in key markets (Alberta, the United Kingdom and Ontario).
- Financial metrics and liquidity at the consolidated level are solid; strong credit ratios and low financial obligations at the holding company level.

Challenges

- Free cash flow deficits are expected at CUI's regulated utilities over the next few years, which will require equity support from CU.
- Regulated utilities faces lower ROEs. ROEs for the electric and gas distribution and transmission operations declined in 2006 to 8.93% from 9.5% in 2005.
- Exposure to commodity price risk remains, as approximately 30% of non-regulated generating capacity sells in the spot market in Alberta and the U.K.; Midstream operations are also subject to gas price volatility.
- There is operational risk at Alberta Power (2000) as the Company must meet minimum availability targets.

SIMPLIFIED ORGANIZATIONAL/DEBT CHART



(1) Estimated by DBRS.

As of September 30, 2006

EARNINGS AND OUTLOOK

	For the 12 months ended				
($ millions)	Sept. 2006	Dec. 2005	Dec. 2004	Dec. 2003	Dec.2002
Revenues	2,440	2,516	3,090	3,743	2,976
EBITDA	1,033	962	904	874	805
EBIT	696	650	612	605	561
Gross interest expense	220	210	210	209	207
Core net income	349	301	290	292	256
Net Income (reported)	313	266	309	259	305
Return on common equity (1)	14.2%	12.2%	12.5%	13.7%	13.7%

(1) Net income before non-recurring items.

Summary

- The Company has experienced consistent EBIT and core net income growth, reflecting increased investments in regulated utilities, a recent strengthening in the midstream business's pricing environment, and improved power markets in Canada and the United Kingdom.
- Earnings growth benefits from new investments in non-regulated generation. This segment accounts for a DBRS-estimated 20% to 25% of EBIT.
- Approximately 70% of non-regulated capacity is sold under long-term power contracts, with the balance exposed (primarily) to the Alberta merchant market.
- Earnings from the midstream business (gas storage, gas gathering and processing) are subject to commodity price volatility. Recently, these businesses have benefited from increased demand for storage.
- Interest expense has remained very stable.
- Earnings stability is supported by CUI's stable regulated utilities, which account for an estimated 55% to 60% of consolidated net income.

Outlook

Modest EBIT growth is expected to continue, which reflects the following:

- Investments in the regulated utilities to meet increases in customer demand and reliability.
- DBRS believes that these investments will generate reasonable regulated returns and support CU's future earnings stability.
- However, earnings from AP (2000) are expected to decline over time as the rate base declines.
- Earnings at the midstream business are expected to continue to remain volatile; but should remain an important source of earnings and cash flow in the near term given the current market strength.
- Non-regulated generation is expected to continue to benefit from a large base of long-term power contracts.
- DBRS expects CU to continue to evaluate additional investment opportunities and acquisitions given their strong financial flexibility and liquidity. DBRS anticipates that the Company will exhibit continued financial and strategic discipline throughout this process.

FINANCIAL PROFILE

Condolidated Cash Flow	For the 12 months ended				
($millions)	Sept. 2006	Dec. 2005	Dec.2004	Dec. 2003	Dec. 2002
Operating Cash Flow	679	614	538	526	505
Dividends	(175)	(140)	(134)	(129)	(124)
Capital expenditures	(565)	(527)	(536)	(496)	(570)
Plus: contributions from customers	68	44	51	48	41
Gross Free Cash Flow	7	(9)	(81)	(51)	(148)
Working capital changes	8	90	102	(53)	(160)
Free Cash Flow	14	81	22	(104)	(308)
Acquisitions	0	0	0	0	0
Business/asset dispositions	(11)	38	20	24	109
Other/adjustments	(22)	21	(5)	(10)	6
Amount to be Financed	(18)	140	37	(90)	(193)
Net change in debt	124	1	332	(111)	183
Net change in preferreds	0	0	0	150	150
Net change in equity	(72)	(3)	(3)	(2)	3
Net change in other	2	(11)	4	(52)	49
Net change in cash	36	126	370	(106)	191
Total debt in capital structure	54.6%	54.8%	56.1%	55.0%	58.1%
EBIT interest coverage	3.16	3.09	2.92	2.90	2.71
Total debt/EBITDA (1)	3.13	3.37	3.62	3.35	3.74
Cash flow/adjusted total debt (1)	21.0%	19.0%	16.5%	18.0%	16.8%
Dividend payout (2)	56.0%	52.6%	52.9%	49.9%	52.3%

(1) Total debt adjusted for preferred and operating lease.

(2) Common dividends divided by net income after preferred dividends.

Summary

CU's consolidated financial profile continues to show modest improvement reflecting the following:

- Higher operating cash flows generally reflecting the earnings growth discussed previously.
- Modestly negative gross free cash flow deficits reflecting reasonably stable capital expenditures and a fairly consistent dividend payout ratio.
- Reduced variability and working capital requirements with the 2004 retail supply sale. Additionally, CU carries a substantial amount of consolidated cash and equivalents ($733 million at September 2006) with much smaller levels of short-term debt.
- Financial ratios have shown gradual year-over-year improvement, with leverage currently at 54.6%, EBIT interest coverage at 3.16 times, and cash flow-to-debt at 21.0%.

Outlook

The financial profile is expected to remain stable going forward reflecting:

- Strong cash flow from operations is expected to continue over the medium term, given the underlying regulated operations and current strength in the non-regulated businesses.
- With annual capital expenditures expected to trend upwards, particularly in the regulated businesses, DBRS expects:
  – Free cash flow deficits primarily at the regulated utility level.
  – Management's current financing strategy is reasonable in that the utilities (CUI) fund free cash deficits with a mix of debt and equity support from CU to keep CU's consolidated debt/capital below 60%. DBRS believes that CU has the financing capability and financial flexibility to adhere to this strategy.
  – As such, key credit ratios are expected to remain reasonably stable.

LIQUIDITY

(As of December 31. 2005)

Obligor	2006	2007	2008	2009	2010	Thereafter	Total
CUI	175	55	100	125	125	1,540	2,120
Non- Recourse	57	52	76	70	77	399	731
CU	0	12	0	0	0	100	112
Total	232	118	176	195	202	2,039	2,962
	8%	*4%*	*6%*	*7%*	*7%*	*69%*	*100%*

Credit Facilities: CU and Subsidiaries* (as of September 30, 2006)

Obligor	Committed Facilities	Amount	Drawn	Available
CU	Short-term	326	22	304
CU	Long-term	300	25	275
CU Inc.	Short-term	300	16	284
($ millions)		926	63	863

* Estimated from Sept. 30, 2006 MD&A's of CU and CUI

Summary

- CU's liquidity position remains strong, reflecting good cash flows, reduced working capital requirements and a strong cash position (over $730 million) relative to short-term obligations.
- The Company has a $200 million commercial paper (CP) program at CU, a $400 million CP program at CUI and sizeable credit facilities.
  - The authorized CP program at CU is fully backed by the Company's committed bank facilities.
  - The authorized CP program for CUI is $400 million, but is backed up by CUI's $300 million credit facility; however, CUI is committed to issuing only up to the back-up amount of $300 million.
- The Company's debt repayment schedule is spread out evenly over the next five years and the annual amounts to be refinanced are viewed by DBRS as moderate and within the financing capacity of CU.
- Non-recourse debt repayments will be funded at the respective power projects and could impact distributions available to CU.

CU HOLDING COMPANY CASH FLOW ANALYSIS

DBRS Estimates		
($ millions)	2005E	2004E
Common dividends from CU Inc.	141	189
Preferred dividends from CU Inc.	14	14
Dividends from other, other	107	43
Cash Flow From Operations	262	246
Interest expense	6	6
Cash Flow Before Dividends	256	240
Less: Preferred dividends	36	36
Cash Flow After Preferred Dividends	221	204
Common dividends	(140)	(134)
Cash Flow After Common Dividends	81	70
Net change in debt	0	0
Net change in equity	(3)	(3)
Net Change in Cash	78	67
Key Ratios		
Cash flow/(preferred + interest expense)(times)	6.3	5.9
Cash flow/interest expense (times)	43.7	41.0
Total adjusted debt/capital*	10%	10%
Cash flow/adjusted debt*	88%	82%
Cash flow (after preferred)/adjusted debt*	76%	70%
Capital Structure		
Total debt issued by CU	100	100
Preferred shares treated as debt (30%)	191	191
Preferred shares treated as equity (70%)	446	446
Common equity	2,242	2,118
	2,978	2,855

* Adjusted debt included portion of preferred shares

- The holding company cash flow analysis is a DBRS estimate formulated primarily using information from CU's published consolidated financial statements. CU does not publicly file non-consolidated financial statements.
- On an non-consolidated basis, subsidiary dividends have provided free cash flow in excess of CU's interest obligations, investments, common dividends to shareholders (including ATCO) and preferred dividends.
- The non-consolidated financial profile remains very strong for CU, reflecting: (1) low adjusted leverage (included a portion of preferred shares) at 10%, (2) cash flow-to-interest-and preferred dividend coverage at 6.3 times, (3) cash flow-to-interest coverage at 44 times, and (4) cash flow-to-debt coverage at 88%.
- Investments in subsidiaries have been moderate over the past several years; however, DBRS believes CU's financial support of its regulated utilities will increase over the next few years to help fund increased capital expenditure requirements resulting from growing customer demand and system reliability.

CU Preferred Shares

In a press release dated October 30, 2006, DBRS upgraded CU's Series O, T, W and X preferred shares (Group 1 Prefs) to Pfd-2 (high) from Pfd-2. This was the result of a review of the structural characteristics of all of CU's cumulative preferred shares.

In the review process, the linkage between CU's publicly issued Series Q, R, S preferred shares, and the privately issued Series U and V preferred shares (collectively the Group 2 Prefs, rated Pfd-2 (high)) and the associated preferred shares issued by CUI's individual utility companies (UtilCos) was re-assessed. The UtilCo preferred shares are held by CU and exactly mirror the terms and conditions of the Group 2 Prefs. DBRS believes that while the Group 2 Prefs benefit from CU's holding of the underlying mirrored UtilCo preferred shares that are the direct obligation of the individual UtilCos (and form part of their regulated capital structure), this linkage is not direct enough to warrant a rating one notch higher than the Group 1 Prefs. As the Group 1 and 2 Prefs are now viewed by DBRS as having similar risk, the ratings on all of CU's cumulative preferred shares have been equalized at Pfd-2 (high).

DESCRIPTION OF OPERATIONS

(A) REGULATED – DBRS ESTIMATED 55% TO 60% OF NET EARNINGS

UTILITIES SEGMENT – (see separate CUI report for more detail)

Strengths

- Regulated businesses provide stability
- Strong credit metrics/good balance sheet
- Strong franchise area

Challenges

- Free cash flow deficits/high capital expenditures
- Operational risk
- Low approved ROEs

(1) Electric Transmission and Distribution

- Serves approximately 210,900 electric customers in Alberta, the Yukon and the Northwest Territories.
- As a result of ATCO Electric's and ATCO Gas's sale of their retail business, neither is responsible for customers' commodity procurement. Working capital and liquidity requirements were also reduced with the sale.
- The business is low risk, with virtually no competition within the franchise areas. Returns on investments are regulated, and as such, regulatory risk is the most significant business risk.
- The regulatory environment is viewed by DBRS as stable, with a reasonable regulatory lag for recovery of operating costs.
- Allowed ROE for 2006 is lower than historically granted, but still remains acceptable at 8.93% on a 37% common equity component for distribution and 33% for transmission.
- Due to increased capital expenditure requirements to meet customer demand and maintain system reliability, the segment is expected to generate free cash flow deficits over the medium term.
- DBRS believes that the segment's financial metrics should remain stable as the Company intends to finance its deficits in a way that will keep the actual debt/capital ratio close to the regulatory allowed ratio.
- Electric transmission and distribution is the largest earnings contributor to CUI.

(2) Gas Transmission & Distribution

- ATCO Gas and ATCO Pipelines operate gas distribution and transmission businesses, serving approximately 939,600 customers.
- Business risk is reasonably low, reflecting a stable regulatory environment, reasonable regulated returns, and no gas price risk.
- The gas distribution business is sensitive to weather, which can significantly influence the segment's cash flow stability.
- Most of the transmission pipelines are strategically located, with increasing demand to connect producers with major pipelines.
- Financial risk is moderate, reflecting the external financing that will be required to finance ongoing capital expenditures. DBRS believes that the Company's financing strategy is reasonable and achievable and will result in continued strong credit metrics.
- Allowed ROE for ATCO Gas declined to 8.93% in 2006 from 9.50% in 2005, with an equity ratio of 38%. The lower allowed ROE will have a modest impact on earnings, but not significant enough to materially impact credit metrics.
- Allowed ROE for ATCO Pipelines is 9.6% with an equity ratio of 43%

(3) Regulated Generation: Alberta Power (2000)

AP (2000) Assets

Name	Type	Nameplate Capacity (MW)	PPA Counterparty	Expiry Date
Battle River (1)				
Unit 3	coal-fired steam turbine	150	Enmax Corp.	2013
Unit 4	coal-fired steam turbine	150	Enmax Corp.	2013
Unit 5	coal-fired steam turbine	370	Enmax Corp.	2020
		670		
Sheerness (2) (3)				
Unit 1	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
Unit 2	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
		380		
Rainbow	natural gas turbine	88	Merchant (4)	
Sturgeon	natural gas turbine	18	Merchant	
		1,156		

(1) ENMAX became PPA purchaser in May 2006.
(2) AP (2000)'s ownership of 760 MW of gross capacity.
(3) TransCanada Energy Ltd. became the PPA purchaser in Jan. 2006.
(4) PPA expired December 31, 2005.

- AP (2000) holds generation assets in Alberta that are subject to legislatively mandated PPAs.
- While AP (2000) is not regulated on an ongoing basis by the Alberta Energy and Utilities Board (AEUB), the PPAs are structured to allow the owners of these assets (generating assets in service as at December 31, 1995) to recover their forecast fixed and variable costs and to earn a rate of return.
- The PPAs incorporate annually adjusted, formula-based ROEs, consisting of a fixed 450 basis point risk premium above forecast ten-year Government of Canada bond yields, adjusted annually.
- In the event of a PPA counterparty default, CUI could terminate the PPA, a process in which the PPA would be deemed to have been sold from the power-buying counterparty to the Balancing Pool. This provides CUI with a strong back-stop credit on these PPAs (the Balancing Pool carries an Issuer Rating of AA, see separate DBRS report).
- AP (2000) faces decreasing earnings as the rate base declines over time.
- Coal costs are fixed through long-term contracts, with such costs reflected in the PPAs.
  - The equity component for the generation assets under the PPAs has been set at 45%, which is reasonable given the business risk. The ROE for 2006 was set at 8.75%, down from 9.49% in 2005.
  - The PPAs incorporate incentives that encourage operating efficiencies and allocate all benefits and risks associated with meeting availability targets to the generator.
- The business risks for AP (2000) established under the PPAs include the following:
  - AP (2000) is subject to an incentive/penalty regime relating to generating unit availability. On a net basis, if penalties exceed incentives the shortfall is expensed in the year it occurs (alternatively, if incentives exceed penalties the excess is amortized to revenues over the remaining life of the PPA).
  - AP (2000) faces potential risk associated with higher-than-forecasted capital expenditures to maintain its power plants.
- Facilities with expired PPAs become merchant generation and are exposed to commodity price risk and decommissioning risk (if decommissioned at expiry of the PPA, decommissioning costs are included in PPAs).
- 88 MW of Rainbow generation became merchant in 2006, with another 300 MW of PPAs at Battle River to expire in 2013.

(B) Non-Regulated – 40% to 45% of Net Earnings

(1) Power Generation (estimated 20% of net earnings)

ATCO Power Ltd. is involved in the development, construction, operation, and management of independent power projects (IPPs) in Canada (Alberta, British Columbia, Saskatchewan and Ontario), the United Kingdom and Australia.

Strengths

- A substantial portion (70%) of capacity is under long-term contracts, reducing exposure to commodity price risk
- U.K. assets benefit from fixed price gas supply contracts until 2010
- CU is the operator of the large majority of its power plants

Challenges

- Non-regulated generation assets are more highly leveraged than regulated assets and create structural subordination for CU.
- Merchant power risk for 30% of capacity
- Contract renewal risk.

Summary

- CU owns 1,318 MW (net) of non-regulated power projects in Canada, the United Kingdom and Australia.
- Many of the larger projects to-date have been financed with non-recourse debt, limiting CU's exposure to the Company's equity investment.
- Although the non-regulated generation is exposed to commodity price risk, as well as currency, operational and counterparty risks, CU mitigates these risks.
  - An average 70% of generating capacity is sold under long-term contracts, with fuel cost pass-through clauses in some contracts.
  - Fixed priced gas supply contracts in the United Kingdom to support its power contracts (over 80%) and the merchant power generation (about 20%).
  - Operating most power projects to manage costs and operational risk.
  - Strong portfolio of counterparties with investment-grade credit.
- Risks with the IPPs are related primarily to the Company's merchant power exposure in Alberta given the high gas price environment and the fact that most of its merchant power is gas-fired.

(as of December 31, 2005)

Project	Fuel	Plant Capacity (MW)	CU Net Ownership (MW)	Project Debt ($millions)	Details
McMahon, B.C.	Gas	120	60	0	PPA to 2014 with BC Hydro (AA)
Primrose, Alberta	Gas	85	34	0	Power/steam to Canadian Natural Resources, excess is merchant or bilateral sales.
Poplar Hill, Alberta	Gas	45	36	0	Merchant
Rainbow Lake, Alberta	Gas	90	36	0	Power/steam to Husky Energy (BBB(high)), excess is merchant
Joffre, Alberta	Gas	480	154	59	Nova Chemicals (BBB(low)) all steam and 25% of energy to 2020; excess merchant.
Valleyview, Alberta	Gas	45	36	0	Merchant
Oldman River, Alberta	Hydro	32	26	0	Merchant
Muskeg River, Alberta	Gas	170	95	76	50% of power / 100% steam to Alberta Oil Sands Project's (AOSP) Muskeg River mine; excels power is merchant.
Scotford, Alberta	Gas	170	136	85	80% of power and 100% of steam AOSP; excess power is merchant.
Cory, Saskatchewan	Gas	260	104	74	Saskatchewan Power Corp. (A(high)) purchases all of the power under a 25-year PPA.
Brighton Beach ON	Gas	580	232	160	Toll with Coral Energy Canada to 2024
Barking, U.K.	Gas	1,000	255	144	Sells all power under contract to 2010.
Heathrow Airport, U.K.	Gas	14	7	0	All energy and hot water sold to British Airport Authority, plc, under contract to 2010..
Osborne, Australia	Gas	180	90	36	Power to Flinders Osborne Pty Ltd and steam to Penrice Soda Prodcuts Pty Ltd, under contracts to 2018
Bulwer Island, Australia	Gas	33	17	0	All power and steam to BP Amoco plc's Bulwer Island refinery to 2021.
				97	ATCO Power Alberta LP.
Total		3,304	1,318	731	
				(57)	less current due within one year
				674	

Note: Any merchant sales are in Alberta and/or U.K. markets.

(2) Global Enterprises Segment (Estimated at 25% of net earnings)

Summary

- This segment includes midstream businesses (natural gas gathering and processing, gas storage), ATCO Frontec (facility management) and ATCO I-Tek (customer services and technology information solutions).
- ATCO Midstream has ownership in 15 natural gas processing and compression facilities, with a gross licensed capacity of over 2,060 million cubic feet per day.
- It also owns and operates over 1,000 kilometres of raw natural gas pipeline and provides services in gas gathering and processing, natural gas liquids extraction and energy services.
  - Future earnings growth over the medium term will likely be realized in new geographic areas such as the far north, east, and west coasts, as well as through contributions from emerging industries such as heavy oil and natural gas from coal.

Note:
All figures are in Canadian dollars unless otherwise noted.

Canadian Utilities Limited
(Consolidated)

Balance Sheet

($ millions)		As at December 31				As at December 3	
Assets	Sept. 2006	2005	2004	**Liabilities & equity**	Sept. 2006	2005	2004
Cash & equivalents	733	825	700	Short-term	225	232	182
Accounts receivable	265	351	373	A/P & accr'ds	286	371	326
Inventories	84	88	173	Other	2	6	14
Deferred gas & electricity cost	0	0	0	**Current Liabilities**	514	610	522
Regulatory assets/other	39	39	25	Deferred credits	584	616	535
				Long-term debt	2,092	2,056	2,046
Current Assets	1,120	1,303	1,270	Non-recourse debt	634	674	761
Net fixed assets	5,318	5,209	5,043	Retract. pfd. shares	0	0	0
Deferred electricity costs	30	35	30	Cumulative pfd. shares	637	637	637
Other	233	269	275	Shareholders' equity	2,241	2,224	2,118
Total	6,701	6,816	6,618	**Total**	6,701	6,816	6,618

Ratio Analysis	12 mos.	For the year ended December 31				
Liquidity Ratios	Sept. 2006	2005	2004	2003	2002	2001
Current ratio	2.18	2.14	2.43	1.69	1.72	1.21
Cash flow/total adjusted debt (1)	21.0%	19.0%	16.5%	18.0%	16.8%	18.2%
Cash flow/capital expenditures (1)	1.32	1.25	1.10	1.16	0.96	0.74
Cash flow-dividends/capital expenditures (1)	1.01	0.98	0.85	0.90	0.74	0.57
% Total debt in capital structure (1)	54.6%	54.8%	56.1%	55.0%	58.1%	59.5%
Common equity in capital structure (1)	37.8%	37.6%	36.3%	36.6%	35.3%	35.4%
Common dividend payout	56.0%	52.6%	52.9%	49.9%	52.3%	50.2%
Coverage Ratios						
EBIT interest coverage	3.16	3.09	2.92	2.90	2.71	2.74
EBITDA interest coverage	4.68	4.56	4.30	4.18	3.88	3.89
Fixed-charges coverage	2.72	2.54	2.38	2.41	2.46	2.58
Total adjusted debt/EBITDA (1)	3.13	3.37	3.62	3.35	3.74	3.38
Return on equity						
Return on avg. equity (before extras.)	14.2%	12.2%	12.5%	13.7%	13.7%	15.0%
Approved ROE - ATCO Electric (T&D)	8.93%	9.50%	9.60%	9.40%	NA	NA
Approved ROE - ATCO Gas (2)	8.93%	9.50%	9.50%	9.50%	9.75%	9.75%
Approved ROE - ATCO Pipelines (2)	9.60%	9.60%	9.60%	9.50%	9.75%	9.75%
Approved ROE - PPAs	8.75%	9.99%	9.99%	9.99%	10.18%	10.29%

(1) Adjusted for preferred and operating lease. DBRS treats 30% of preferred shares as debt.
(2) For 2003 and 2004 test years, applied for combined revenue requirements for north and south divisions.