



ZAP!

ALBERTA IS JOLTED BY ELECTRIC DEREGULATION

SUMMARY

Alberta is further advanced in the process of deregulating its electric industry than any other Canadian province. Full retail competition commenced in Alberta on January 1, 2001. Currently, the province sets wholesale electricity prices through an auction process, where supply offers and purchaser bids are made through the Power Pool of Alberta (PPOA). In unnerving similarity to California's experience, this process has resulted in Alberta's power prices increasing from amongst the lowest in the world to among the highest prices in North America. The provincial government has recently made changes to its Electric Utilities Act in an attempt to mitigate the market forces that are driving power prices higher. However, we believe that the changes will have little impact on the Albert Pool Price. While other Canadian provinces will find some relief from the North American energy crisis through relatively low-cost electricity, the trend for power prices in Alberta is expected to increase.

In this report, we build on our June 2, 2000 report entitled *Electric Competition Unfolds in Alberta*, examining the factors that have contributed to stratospheric electric prices, assessing the sustainability of current power prices in Alberta, and identifying Canadian companies in the pipeline and gas & electric sectors that we believe are best positioned to benefit from high Alberta power prices.

HIGHLIGHTS

- Electric prices in Alberta have increased from average levels of approximately \$14.50 per megawatt hour (MWh) in 1996 to an average of \$223.80 per MWh in the fourth quarter of 2000.
- On November 28th, the government of Alberta announced that Alberta residential and commercial electricity rates would be held virtually constant for one year. In addition, new regulations were enacted governing how the Power Pool Administrator sets Pool prices involving imports and exports of electricity and expanding the number of suppliers eligible to sell power directly to Alberta consumers.
- We believe that, in the absence of further regulatory changes by the provincial government, power prices in Alberta will remain high for several years. Companies that have merchant generation capacity upon which they can capitalize include **ATCO** (ACO.X¹ \$43.60), **Canadian Utilities** (CU¹ \$49.20), **Westcoast Energy*** (W \$32.80) and **TransCanada PipeLines** (TRP \$16.25), which are all ranked 2 (OUTPERFORM), and **TransAlta** (TA \$22.45), ranked 4 (UNDERPERFORM).

¹ Non-voting shares.

* Within the past 12 months, RBC Dominion Securities has undertaken an underwriting liability or has provided advice for a fee with respect to the securities of this company.

TABLE OF CONTENTS

OVERVIEW	3
CONTRIBUTING FACTORS TO PRICE INCREASES	4
Regulated Prices	4
Competitive Pricing.....	4
THE ALBERTA GOVERNMENT INTERVENES IN THE COMPETITIVE PROCESS	6
Alberta Government Caves Under Price Pressure.....	6
Other Changes	7
DEFERRAL ACCOUNT RISK	8
ELECTRIC SUPPLY AND DEMAND IN ALBERTA	9
Demand	9
Supply.....	9
Outlook.....	11
Interconnections	11
IMPLICATIONS FOR INVESTOR-OWNED UTILITIES	13
ATCO Ltd.	15
Canadian Utilities	16
TransAlta Corp.....	17
TransCanada PipeLines.....	18
Westcoast Energy	19
CONCLUSION	20
APPENDIX I – DEREGULATION IN CALIFORNIA	21
Background	21
Summer 2000	22
Fall/Winter 2000	23
Placing the Blame.....	24
Fixing the Problem.....	24
APPENDIX II – RESULTS OF ALBERTA’S DECEMBER ELECTRICITY AUCTION	27

OVERVIEW

Alberta Leads Canadian Provinces In The Transition Towards A Competitive Market For Electricity

Alberta is by far the most advanced province in Canada with respect to deregulating electric markets. Alberta commenced the process of restructuring the industry in 1993. This eventually led to the *Electric Utilities Act, 1995* and the subsequent *Electric Utilities Amendment Act, 1998*. The Electric Utilities Act (“EUA”), as amended, established a framework for deregulation of the electric industry by 2001. Under this framework, generation and retail services businesses would be deregulated, while transmission and distribution businesses would remain regulated.

Initially, Deregulation Had Little Impact On Power Prices

Alberta commenced the transition to a fully competitive market for wholesale power on January 1, 1996. Initially, there was little generation in the province that was not owned by the three regulated utilities: TransAlta, Alberta Power and EPCOR. There was, and remains, no direct interconnection with the U.S. and for several years prices paid by electric customers largely remained at levels that were among the lowest in the world.

Alberta Prices Have Mirrored Those In California

On September 24, 1997, BC Hydro opened its transmission lines to third parties as part of the requirement to obtain a Federal Energy Regulatory Commission (FERC) licence. Prior to this, with the exception of Powerex (the marketing arm of BC Hydro), marketers had no opportunity to import and export power between Alberta and the U.S. In addition, the California electricity market did not open its doors to competition until March 1998, providing the first major market for exports of electricity. Since these changes were enacted, the Power Pool Price in Alberta has essentially mirrored that of California.

Crisis Hit The Summer Of 2000

For two years following the opening of the California market, prices remained reasonable. Between April 1, 1998 and May 19, 2000, the average daily price of wholesale electricity on the California Power Exchange was approximately US\$28.50 per MWh. However, following a heat wave that hit California in the summer of 2000, the electric system in the state was thrown into a crisis from which prices have not fully retreated.

Wholesale Power Prices In Alberta Have Increased By Over 650% Since 1997

In Alberta, the wholesale price of power has increased from the 1997 average cost of \$20.39 per MWh to an average Power Pool price of approximately \$133 per MWh in 2000. During December 2000, the average price of power in Alberta was approximately \$189 per MWh.

CONTRIBUTING FACTORS TO PRICE INCREASES

*Move From Average Cost To
Marginal Cost Increases
Alberta Power Prices*

There are a number of variables that enter the equation regarding the dramatic increase in power prices in markets that deregulate. However, in our view, the most relevant factor is the change from pricing the commodity (electricity) at the average cost of the total projected demand to a single price equal to the marginal cost of the last kilowatt-hour of electricity required. The price impact from pricing at the marginal cost rather than the average cost is particularly dramatic in a jurisdiction such as Alberta that starts the deregulation process with a low average cost of existing generation.

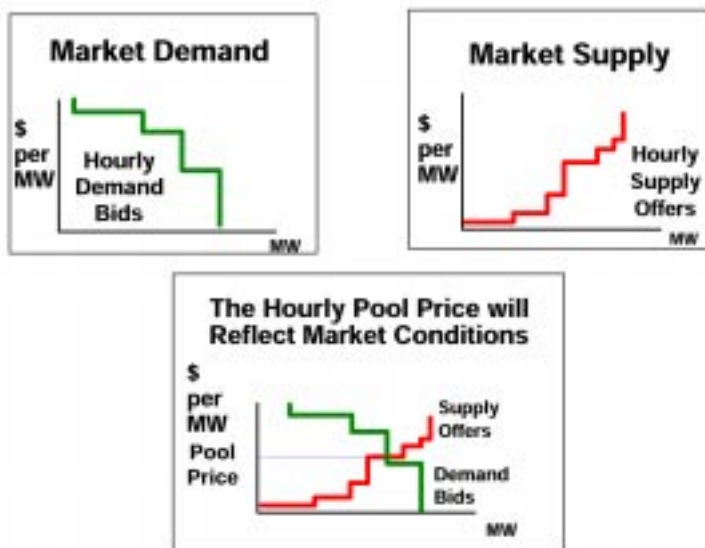
REGULATED PRICES

Under traditional regulation, prices are set to recover the average costs of power, including a return on capital invested. Power costs in Alberta have historically been among the lowest in Canada, which, in turn, are among the lowest in the world. In 1996, the average industrial rate in Edmonton was approximately US\$29 per MWh versus the national average of US\$40 per MWh and US\$46 per MWh for the U.S. If high imported power prices were paid in Alberta to acquire power to satisfy demand spikes, the incremental cost was rolled into the total average cost and recovered in future rates.

COMPETITIVE PRICING

Under the competitive pricing methodology initially employed by the Power Pool of Alberta (PPoA) bid/offer blocks were submitted to the Pool on an hourly basis. Distributors and **exporters** placed hourly bids to indicate how much power they were willing to buy at different prices. Bids were ranked according to willingness to pay from the highest to lowest. Generating units and **importers** offered blocks of power into the Pool at the prices they were willing to accept. Offers were ranked by price from lowest to highest. The bids and offers formed the basis for a forecast of what load would be served and which units would be dispatched in the hour. The actual Pool price was the highest price unit block dispatched during the hour to balance the supply and demand in the system. The process is illustrated in the graphs below.

Graph I: PPoA's Competitive Pricing Methodology

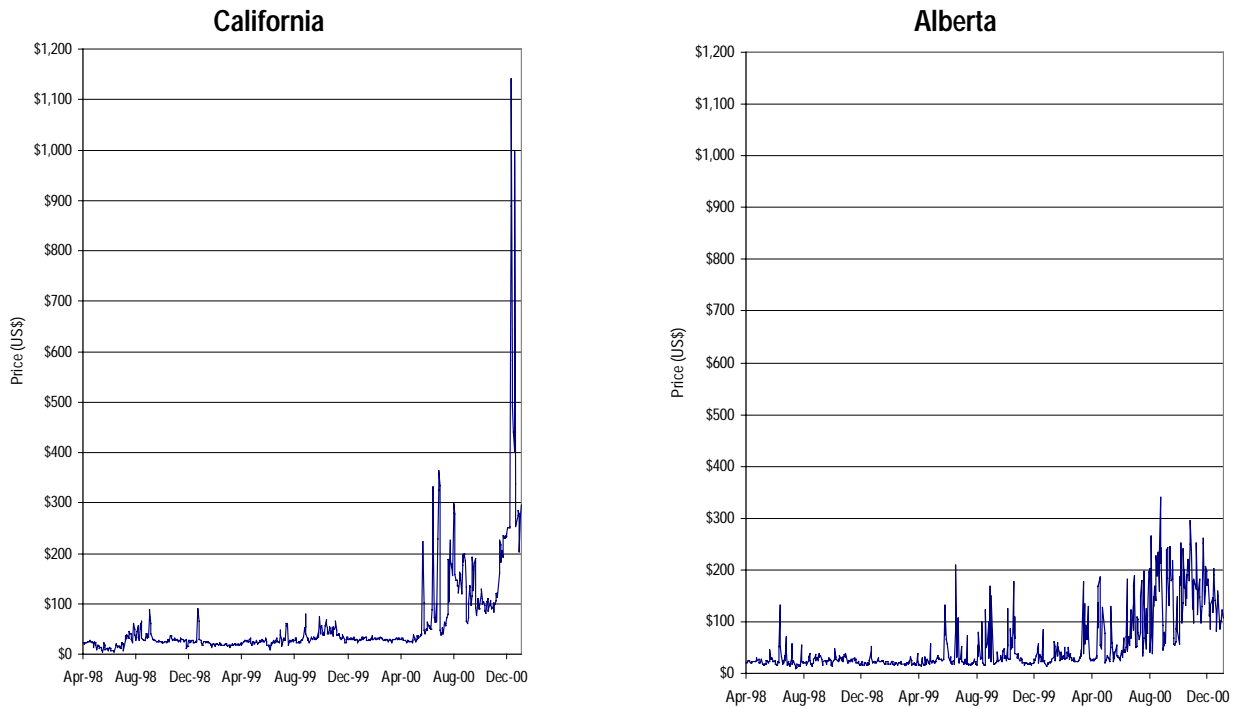


Source: Alberta Resource Development

With Competition Comes The Theory Of One Price

We believe that under this original methodology the power shortage in California and the associated price spikes in that market were contributing factors to the surge in Power Pool prices in Alberta. Power traders with access to transmission capacity, which for the most part was BC Hydro’s Powerex, could simply arbitrage power between Alberta and the Pacific Northwest markets. The graphs below illustrate the similarity between price moves in California and Alberta.

Graph II: Electricity Prices (US\$/MWh)



Source: Bloomberg, Power Pool of Alberta

The relationship between the price of power in Alberta and that in California was somewhat decoupled in December 2000 due to the change in Alberta’s Electric Utilities Act, which excluded import and export transactions in calculating the Pool Price. In addition, both BC Hydro and TransAlta ceased making sales to the California Independent System Operator and the three large California electric distribution utilities due to concerns that these entities were on the verge of bankruptcy.

The dramatic rise in Alberta’s power prices led to claims by the Alberta Market Surveillance Administrator that Powerex was unfairly restricting power traders’ ability to move electricity from the U.S. Pacific Northwest to Alberta across its high-voltage transmission network, thereby contributing to high Alberta power prices. After an investigation into suspected electricity price fixing by Enron Canada Corp. and Powerex Corp., the Canadian Competition Bureau concluded that there was no evidence that the two companies colluded to fix prices. However, we believe that given the tight supply/demand situation in Alberta, the Pacific Northwest and California, market prices in Alberta will continue to be set by the highest netback market¹ even with open access to transmission and in the absence of alleged “price fixing”.

¹ The highest netback market will equal the highest regional market price less the cost of transmission to reach that market.

THE ALBERTA GOVERNMENT INTERVENES IN THE COMPETITIVE PROCESS

ALBERTA GOVERNMENT CAVES UNDER PRICE PRESSURE

*Despite Changes To The
Electric Act, Prices In Alberta
Could Stay High For Some
Time*

*Outage At Wabamun Plant
Exacerbates Supply Shortage*

*With Adequate Supply, Price
Should Equal Marginal Cost*

In the PPOA's November 20th document, *Potential Market Rule Changes for Discussion*, suggestions were put forward to address the issue of skyrocketing power prices in the province of Alberta. The PPOA's primary recommendation involved the concept that interconnections (import and export prices) should not be allowed to set the Pool Price in Alberta. To accommodate the interconnections, it was suggested that a one-hour forward market be established exclusively for the interconnections. In the Order in Council filed on November 28, 2000, the recommended change to the Electric Utilities Act states that "...the Power Pool Administrator must exclude the price of electric energy entering or leaving the interconnected electric system." The change to the Act came into force on December 15, 2000.

While this change may have some impact on power prices in Alberta, it is important to note that the revised rules do not restrict imports and exports of power to Alberta, nor do they restrict the prices at which these transactions occur. Rather, the change "de-couples" the Pool price from import and export prices. However, if the price differential between Alberta and the Pacific Northwest is larger than the cost of transmission between the two markets, and if transmission capacity is available, exports of power could lead to supply constraints in Alberta and price spikes on peak load days could still occur. The interconnection between Alberta and B.C. is approximately 800 MW, or 9% of the intra-Alberta supply of 9,000 MW. There is no direct interconnection between Alberta and the U.S. Average system demand in Alberta in 2000 was approximately 6,154 MW.

With TransAlta's 286-MW Wabamun IV unit taken off line for unscheduled maintenance through to mid-2001 and with peak load days in Alberta requiring up to 7,400 MW, the demand/supply situation remains very tight.

In the long run, as supply of generation is added, we expect the cost of power to equal the marginal cost of the last kilowatt of power dispatched. Assuming that the incremental kilowatt hour of power is from a gas-fired combined cycle co-generation facility and assuming an Alberta price of gas equal to US\$4.00 per MMBtu, the approximate marginal cost of power would be C\$57.00 per MWh.

Table I breaks down the total supply of generation during 1999/2000 by source.

Table I: Overview of Alberta Electricity System – 1999/2000 Capacity (MW)

	Coal	Gas	Hydro	Total Capacity	Available to Alberta Interconnected Electric System	% of Total Available Capacity
Utility Generation						
ATCO Electric	1,563	104	-	1,667	1,667	18%
EPCOR Generation	768	841	-	1,609	1,609	17%
TransAlta Utilities	3,290	-	795	4,085	3,805	41%
Emergency Capability	-	-	-	-	126	1%
Medicine Hat	-	211	-	211	40	0%
	5,621	1,156	795	7,572	7,247	78%
Non-Utility Generation						
Industrial				958	100	1%
New IPPs				1,365	128	1%
Small Power				128	910	10%
				2,451	1,138	12%
Interconnections						
BC Hydro				800	800	9%
SaskPower				150	150	2%
				950	950	10%
TOTAL				10,973	9,335	

Source: Alberta Resource Development

OTHER CHANGES*Residential And Commercial Rate Freeze*

Under the authority of the Electric Utilities Act, the government has directed the Alberta Energy and Utilities Board to review electricity prices across the province and suspend current hearings on proposed “rate rider” surcharges for the duration of the review. Rate rider surcharges refer to rate increases for the recovery of corporate shortfalls created by the high cost of wholesale electricity purchased on the Power Pool of Alberta. Previously approved rate hikes resulting from rate riders scheduled for 2001 will also be suspended for one year.

Utilities Will Accumulate Uncollected Power Costs In Deferral Accounts

Under the government’s plan, utilities affected by the suspension of rate rider surcharges will eventually be allowed to recover any corporate shortfalls arising from the high cost of wholesale electricity. Such shortfalls, plus related interest charges, will be recoverable over a three-year period starting in 2002. In cases where utilities had to borrow to finance the revenue shortfall in 2000, Alberta’s Balancing Pool will pay the interest on the debt until 2002. In summary, while cash flows will be affected, the government’s rate freeze is not expected to have a significant impact on the earnings of the affected utilities. Nevertheless, credit rating agencies may become concerned regarding the size of the deferral accounts and the associated debt to finance the cost of acquiring power over and above what can be recovered in rates charged to customers.

Regulated Rate Option Keeps Customers’ Rates Constant Through 2001

On November 30th, responding to concerns expressed by Alberta consumers about rising electricity prices, the government set the province-wide price for power under the Regulated Rate Option (RRO) at \$0.08 per kWh for 2001. Following the second auction of Power

Purchase Arrangements in Alberta, where the average base load power price was \$0.117, the RRO was increased to \$0.11 per kWh. Retail electricity providers and customers may ask the Energy and Utilities Board to review this prescribed RRO energy charge after April 1, 2001. When combined with customer rebates, which average approximately \$0.06 per kWh, customer rates for 2001 should be \$0.05 per kWh, or flat with the average wholesale cost of power in 2000.

Table II: Residential Wholesale
Cost of Power (\$/kWh)

Average wholesale cost of power in 2000	\$0.05
Energy rate in 2001	\$0.11
Electricity auction rebate (\$40/month) ¹	<u>(\$0.06)</u>
Average wholesale cost of power in 2001	\$0.05

¹ Based on an average consumption of 650 kWh per month

Source: Alberta Resource Development

The government's position is that the above energy rate – when combined with a utility company's usual charges for the regulated transmission and distribution of power and administrative costs – means the average consumer's power bill will remain virtually unchanged during 2001 from what it would have been under regulation.

Although the rate charged under the RRO will undoubtedly increase in future years, the option will be available to residential and farm-home electricity customers for five years. Commercial power customers who use less than 250,000 kWh per year will be eligible to receive the RRO for up to three years. Approximately 1 million customers, representing 95% of Alberta's power consumers, are residences, farms and small businesses and will be eligible to select the RRO. Approximately 35% of the power consumed in Alberta falls under the RRO. The remaining 65%, used by large industrial, municipal and commercial consumers, will remain deregulated and unaffected by the RRO.

DEFERRAL ACCOUNT RISK

With the Alberta electric distribution utilities unable to pass on the full costs of electricity to their customers as they are incurred, investors may be concerned regarding the risk surrounding the future recovery of such costs. Concern regarding the probability of this situation will be magnified by the California experience, where there is a significant risk that the distribution utilities will go bankrupt due to their inability to pass on skyrocketing electric costs to their customers.

Under California's 1996 deregulation law, customers of three utilities – Southern California Edison, Pacific Gas & Electric and San Diego Gas & Electric – had their rates frozen after a 10% roll-back. The law stated that the rate freeze would last until March 2002 or until the utilities finished paying off billions of dollars of past debts from investments in nuclear and alternative energy, whichever came first.

San Diego Gas & Electric paid off its past debts early and its customers were lifted out of the rate freeze in 1999. Residents paid the market price of electricity until prices got so steep last summer that the Legislature intervened and capped rates.

*The California Situation Is
Different*

*Suggested Rate Increases By
CPUC Will Hardly Dent The
US\$12 Billion Deficit*

At the end of December, Southern California Edison and Pacific Gas & Electric reported a combined loss of approximately US\$12 billion due to the sharp increase in wholesale electric prices. In light of their dire financial situation, the CPUC recently approved a temporarily lifting of the freeze on the electric rates of Pacific Gas & Electric and Southern California Edison pending the results of an independent audit of the utilities' financial position. The CPUC approved rate increases of 9% for 90 days for residential customers and 7%-15% for commercial customers for the two utilities. PG&E had asked for a 26% rise in rates, while Southern California Edison wanted a 30% increase to help recover costs.

As described in the Appendix I of this report, one material difference between the California situation and that in Alberta is that in California all three investor-owned electric utilities agreed to the rate reduction and subsequent rate freeze. In return, the utilities were able to recover US\$28 billion in stranded costs by charging a Competition Transition Charge.

In Alberta, the utilities did not agree to freeze their rates. In addition, there is a significant body of precedent cases of utilities fully recovering all prudently incurred commodity costs. We believe the risk of non-recovery of such costs is minimal.

ELECTRIC SUPPLY AND DEMAND IN ALBERTA

DEMAND

Using data obtained from ESBI Alberta Ltd. (Alberta's Transmission Administrator), we estimate annual electric demand growth of between 0.9% and 4.4% for 2001 to 2010. The estimated average growth rate for the period is 3.0%. In our calculation of average demand, we assume a load factor of 80% and factor in an additional 5% for system losses. Our calculations are set out in the table below. The strong economic outlook for the province is expected to drive growth in electric demand.

Table III: Alberta's Electric Demand Growth

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Total Load - Winter Peak Forecast (MW) ¹	7,291	7,379	7,704	7,946	8,138	8,516	8,733	9,084	9,338	9,595	9,857
Required Generation Plus Reserve (MW)	7,656	7,747	8,089	8,343	8,545	8,942	9,170	9,539	9,805	10,075	10,350
Estimated Average Demand (GWh)	53,798	54,294	56,687	58,467	60,047	62,662	64,263	66,847	68,901	70,602	72,534
Estimated Annual Demand Growth Rate		0.9%	4.4%	3.1%	2.7%	4.4%	2.6%	4.0%	3.1%	2.5%	2.7%

Average Estimated Annual Demand Growth 3.0%

¹ Source: ESBI Alberta Ltd.; Not including system losses, on-site loads or exports

SUPPLY

Total generation capacity available to the Alberta Interconnected Electric System (AIES) in 1999/2000, excluding interconnections, was approximately 8,385 MW. Between 1998-2000, approximately 900 MW of new generation available to the AIES came on line and approximately 2,500 MW of available capacity is expected to come on line within the next five years.

Table IV provides a summary of new and proposed generation in Alberta. Assuming that Power Purchase Arrangement (PPA) terms are representative of the useful life of their respective power plants, units with almost 1,500 MW of generation will have to be replaced or refurbished over the next 10 years.

Table IV: Alberta's New Generation Capacity

Developer	Location	Installed Capacity (MW)	Type	Status
<u>On Line</u>				
Amoco/ATCO Power	Primrose	84	Cogeneration	
ATCO Power	Poplar Hill	43	Gas Turbine	
ATCO Power	Rainbow	45	Gas Turbine	
TransCanada	Gold Creek	6.5	Waste Heat	
Drayton Valley Power	Dapp	17	Biomass	Small power R&D program
Magrath Energy Corp.	Rocky Mountain House	0.9	Flare Gas	
Syncrude Aurora	Fort McMurray	82	Cogeneration	
Air Liquide/TransAlta	Dow Chemical Fort Saskatchewan	120	Cogeneration	
Renaissance	Taber	3.3	Flare Gas	
Canadian Gas & Electric	Drywood	6	Natural Gas	
Vision Quest	Castle River	11.8	Wind	
NOVA/ATCO/EPCOR	Joffre	416	Cogeneration	Commissioning
TransAlta	Poplar Creek / Suncor	360	Cogeneration	290 MW on line (remainder in Jan. 2001)
Canadian Hydro	Taylor Chute	12.8	Hydro	
Air Liquide	Scotford	82	Cogeneration	
Crestar Energy	Grand Forks	1	Flare Gas	
New generation (1998-2000)		<u>1,291</u>		Approx. 890 MW available to AIES*
<u>Under Development</u>				
PanCanadian Petroleum Ltd.	Strathmore	106	Natural gas	On line Sept. 2001
TransCanada	Carseland	81	Cogeneration	On line Nov. 2001
TransCanada	Redwater	46	Cogeneration	On line Nov. 2001
Canoxy/PanCanadian	Calgary	106	Natural gas	On line Dec. 2001
ATCO Power	Muskeg	172	Cogeneration	On line 2002
ATCO Power	Scotford	150	Cogeneration	On line Oct. 2002
Canfor/ Can. Gas & Elec.	Grande Prairie	20	Waste Wood	On line 1st. quarter 2002
ATCO Energen	Oldman	25	Hydro	On line 2nd quarter 2002
EPCOR	Edmonton (Rossdale)	170	Combined cycle	On line 3rd quarter 2002
Calpine Corp.	Calgary	250	Natural gas	On line 2003
(Name Confidential)	Edmonton	30	Cogeneration	On line 3rd quarter 2003
AES Calgary	Calgary area	525	Gas	2003
EPCOR	Genessee	400	Coal	2005
ENMAX / Fording Coal	Brooks area	400	Coal	2005
Canadian Hydro	Dunegan	40	Hydro	Preliminary evaluation
Syncrude Aurora	Fort McMurray	238	Cogeneration	Staged Development
		<u>2,759</u>		Approx. 2,525 MW available to AIES*

*AIES = Alberta Interconnected Electric System

Sources: Alberta Resource Development

*AIES = Alberta Interconnected Electric System

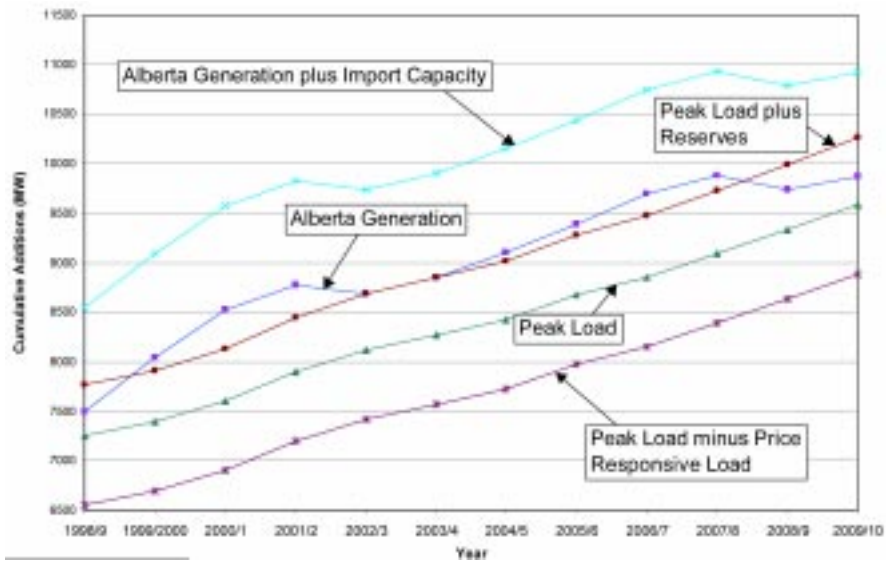
Source: Alberta Resource Development

OUTLOOK

Short-Term, Demand For Power Is Relatively Inelastic. Longer Term, We Could See An Oversupply Situation Of New Generation.

According to ESBI Alberta Ltd., winter peak load in Alberta is projected increase to 8,516 MW by 2005. This implies that 8,942 MW of generation will be required to satisfy winter peak load, assuming a 5% reserve for system losses. By 2005, we expect that capacity from utility generation and independent power producers will increase to over 11,000 MW. We believe that, on a province-wide basis, generation capacity should be sufficient to meet demand requirements over the medium to long term. This conclusion is consistent with ESBI Alberta Ltd.'s 1998-2009 forecasts as shown in the following graph. However, this demand forecast was constructed under the assumption of much lower electricity prices. While demand for power may be inelastic in the short run, in the longer run we expect that plant closures and shut-downs will have an impact on the growth in demand. Further, we believe that there is a material possibility that new power capacity is overbuilt in four or five years.

Graph III: Electrical Energy Supply and Demand 1998 to 2009 (Winter Peak Forecast)

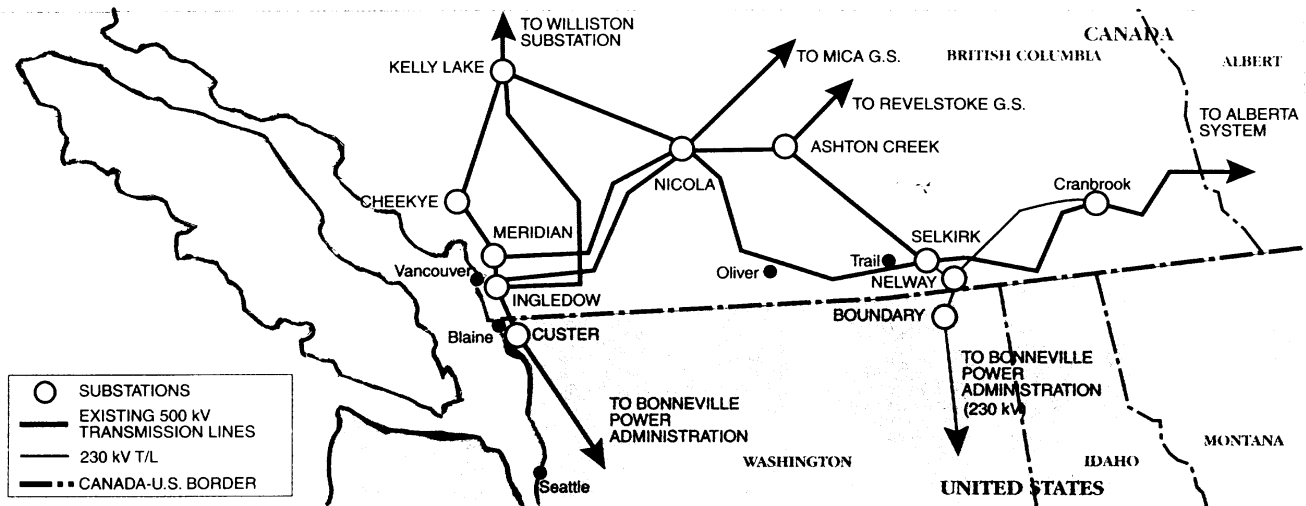


*Note: 1998/99 values are actual
Source: ESBI Alberta Ltd. (AIES Transmission Development Plan 2000-2009 (December 1999))

INTERCONNECTIONS

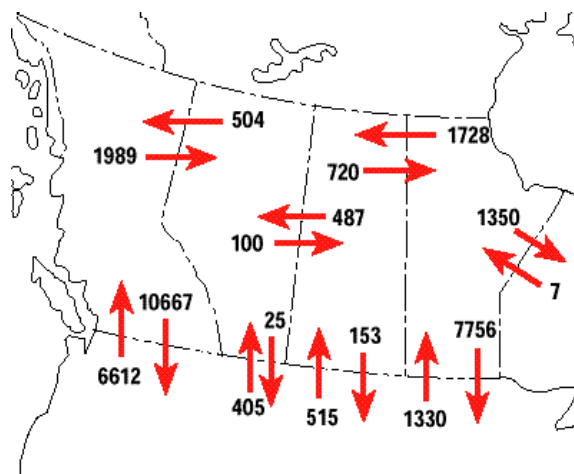
Alberta's electric supply and demand is also dependent on imports and exports of electricity. The province has an 800-MW interconnection with British Columbia and a 150-MW interconnection with Saskatchewan. Alberta has no direct interconnections with the United States and is dependent on utilizing BC Hydro's transmission system to access the U.S. market.

Figure I: Interties to Alberta and the U.S.



Source: BC Hydro (Making the Connection, April 2000)

Figure II: International And Interprovincial Transfers Of Electricity (Gigawatt Hours) In Western Canada For 1999



Note: The above map does not necessarily reflect the physical flow of electricity, which may be different.
Source: National Energy Board

IMPLICATIONS FOR INVESTOR-OWNED UTILITIES

To the extent that companies hold merchant or unhedged generation capacity, they should have exposure to the opportunities and risks associated with variations in the Alberta Pool Price of power. In the absence of further intervention into the free market process by either California or Alberta government officials or regulators, we believe that supply constraints in these markets will keep the price of power significantly above the marginal cost for two to three years.

The view that power prices will remain high in Alberta for several years appears to be shared by many market participants. In Alberta's second auction of Power Purchase Arrangements that was concluded the first week of December 2000, 2,800 MW of generation output was sold for one-year terms for 2001, 2002 and 2003 at per megawatt baseload prices of \$116.63, \$66.82 and \$60.07, respectively. While the 2002 average price drops precipitously from the 2001 price, we believe this is largely due to risk aversion on the part of the bidders. In the absence of further changes in the market rules and/or structure of either the California or Alberta electricity industries, we believe that prices in 2002 will be higher than the auction price of \$66.82 per MWh.

If current electricity price levels persist for several years in Alberta, companies with merchant or uncommitted generation capacity should be able to capitalize on their positions, thereby increasing their earnings. In Table V, we summarize the merchant electricity positions of investor-owned pipelines and gas & electric utilities. It should be noted that we have not included the Power Purchase Arrangements generation capacity that was sold during the December 5th, 2000 Alberta auction in this table as the amount of generation capacity purchased by the various companies was not made publicly available. However, the list of successful purchasers in the auction is presented in Appendix II. In the pages following, we present summaries for each of these companies along with our investment opinion.

Table V: Merchant Capacity Available in Alberta

	Total Generation Capacity (MW)	Merchant Capacity (MW)	Ownership Interest	Total Available Merchant Capacity (MW)	Total Available Merchant Capacity Per Share (Watts)
Westcoast Energy					
<i>Power Purchase Arrangements</i>					
Rainbow	93.0	93.0	100.0%	93.0	
Rossdale	203.0	203.0	100.0%	203.0	
				<u>296.0</u>	2.5
TransAlta					
<i>Power Purchase Arrangements</i>					
Excess capacity	n.a.	n.a.	100.0%		
<i>Independent Power Plants</i>					
Syncrude	265	n.a.	100.0%	200.0 (1)	
Fort Saskatchewan	120	n.a.	60.0%		
Suncor	360	n.a.	100.0%		
				<u>200.0</u>	1.2
TransCanada					
<i>Power Purchase Arrangements</i>					
Sundance A	560.0	110.0	100.0%	110.0	
<i>Independent Power Plants</i>					
Redwater	40	22.0	100.0%	22.0	
Carseland	80	20.0	100.0%	20.0	
				<u>152.0</u>	0.3
Canadian Utilities					
<i>Independent Power Plants</i>					
Primrose	85.0	65-70	40.0%	40.6 (2)	
Poplar Hill	43.0		80.0%		
Rainbow Lake	43.0		80.0%		
Joffre Cogeneration	416.0	208.0	32.0%	66.6	
				<u>107.1</u>	1.7
ATCO Ltd.					
<i>Independent Power Plants</i>					
Primrose	85.0	65-70	10.0%	10.1	
Poplar Hill	43.0		20.0%		
Rainbow Lake	43.0		20.0%		
Joffre Cogeneration	416.0	208.0	8.0%	16.6	
51.9% Ownership interest in CU	n.a.	107.1	51.9%	55.6	
				<u>82.4</u>	2.7

(1) Approximately 4% of TA's generation capacity in Alberta is merchant power

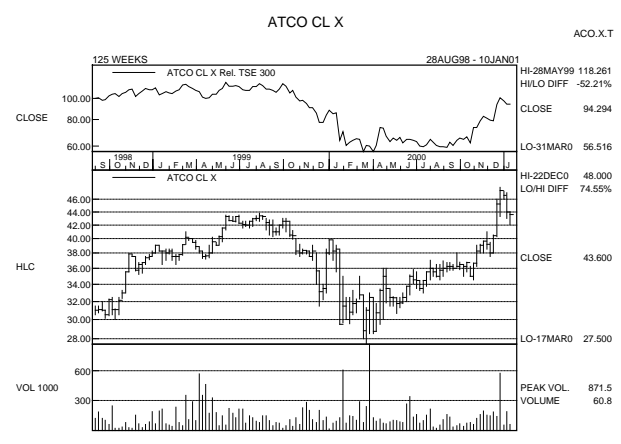
(2) CU's share of merchant capacity is based on the assumption that the total available merchant capacity for each plant is proportional to its total generation capacity.

Note: Total Available Merchant Capacity Per Share does not reflect the cost of generation, which will vary between each company.

ATCO LTD.

		TSE - ACO.X¹ - \$43.60	
Stock Rating (Recommendation)	2 (OUTPERFORM)		1 Yr. Target \$51.25
Industry Rating	2 (MARKETPERFORM)		Annual Return 19.7%
Shares Outstanding Basic (MM)	30.0		
Float (MM)	22.0		
Market Capitalization (\$MM)	\$1,308.0		
Value of Float (\$MM)	\$959.2		
Major Shareholders	Ronald D. Southern (27%)		
Year End	Dec. 31		
52-Week Price Range	\$27.50-\$48.00		
Debt/Total Capital	0.1		
NAV	\$54.58	Discount	20.1%
Dividend	\$0.92	Yield	2.1%
	1999	2000E	2001E
Basic EPS (\$)	3.38	3.82	3.88
F.D. EPS (\$)	3.28	3.73	3.78
P/E (X)	13.3	11.7	11.5
		2002E	4.01
			3.91
			11.2

¹ Non-voting shares



INVESTMENT ATTRIBUTES

ATCO is a holding company with two principal investments: its 51.9% ownership in Canadian Utilities (electrical power generation, transmission and distribution, natural gas distribution and transmission) and its wholly-owned subsidiary ATCO Structures (industrial workforce housing).

INVESTMENT OUTLOOK

ATCO's performance is derived primarily from the performance of its main subsidiary, Canadian Utilities, which has demonstrated good growth potential in its core domestic regulated operations. ATCO should also continue to benefit from the strong performance of ATCO Structures and we expect attractive dividend increases over the next few years. ATCO has traditionally traded at a 20% -25% discount to its estimated net asset value (NAV) and is currently trading in this range. We believe that ATCO's low P/E, attractive EPS and dividend growth and low investment risk support our 2 (OUTPERFORM) ranking.

POWER EXPOSURE IN ALBERTA

ATCO is exposed to Alberta's power prices through both its indirect ownership of independent power plants via Canadian Utilities and its direct interest in four plants. The Primrose, Poplar Hill and Rainbow Lake power plants have an estimated combined merchant capacity of 65-70 megawatts. The Joffre plant is reported to have an additional 208 megawatts of merchant capacity.

Of the Canadian investor-owned utilities, ATCO has the highest per share ownership position of merchant capacity at 2.7 Watts per share. The attractiveness of this capacity is enhanced by the high efficiency rates of the plants owned.

INDEPENDENT POWER PLANTS

Joint Investments with Canadian Utilities

In its 1997 annual report, ATCO announced that it would have the option to invest in up to 20% of Canadian Utilities' non-regulated businesses. To date, ATCO has exercised its option to acquire 20% of Canadian Utilities' interest in the Primrose co-generation plant, the Poplar Hill power plant located near Grande Prairie, Alberta, the Rainbow Lake power plant in Alberta, and the Joffre co-generation power plant.

IPP Summary

The following table provides a summary of ATCO's independent power plants in Alberta that are currently operational, under construction or under development.

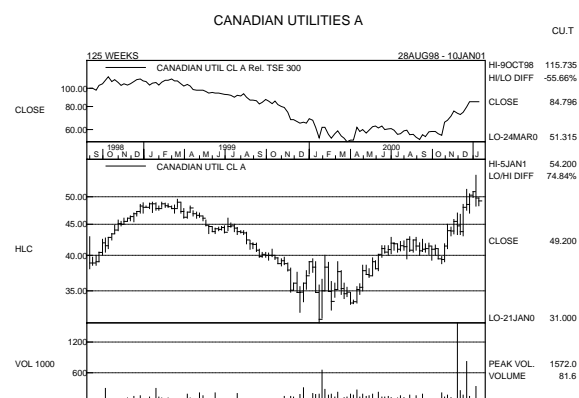
Independent Power Plant	Ownership Interest	Location	Capacity (megawatts)
Poplar Hill Power Station	20%	Grande Prairie, Alta.	43
Primrose Cogeneration Project	10%	Northeast, Alta.	85
Rainbow Lake, Alberta	20%	Rainbow Lake, Alta.	43
Joffre Cogeneration Plant	8%	Joffre, Alta.	416
Muskeg River (1)	20%	Fort McMurray, Alta.	170

Note: (1) Under development

CANADIAN UTILITIES

TSE - CU¹ - \$49.20

Stock Rating (Recommendation)	2 (OUTPERFORM)			1 Yr. Target	\$57.00
Industry Rating	2 (MARKETPERFORM)			Annual Return	19.5%
Shares Outstanding Basic (MM)	63.4				
Float (MM)	30.6				
Market Capitalization (\$MM)	\$3,119.3				
Value of Float (\$MM)	\$1,505.5				
Major Shareholders	ATCO (51.9%)				
Year End	Dec. 31				
52-Week Price Range	\$31.00-\$54.20				
Debt/Total Capital	0.47				
Dividend	\$1.80	Yield	3.7%		
	1999	2000E	2001E	2002E	
EPS (\$) Fully Diluted	3.15	3.52	3.60	3.70	
P/E (X)	15.6	14.0	13.7	13.3	

¹ Non-voting shares.

INVESTMENT ATTRIBUTES

Canadian Utilities is a holding company whose principal operating subsidiaries are engaged in electric energy and natural gas utility operations in Alberta. The company's primary operating areas are: electric power generation, transmission and distribution; natural gas gathering, processing, transmission and distribution; and facilities management and logistics. The company is controlled by its parent ATCO, which holds 51.9% of the outstanding shares.

INVESTMENT OUTLOOK

Canadian Utilities is ranked 2 (OUTPERFORM) due to its growth potential in its independent power projects, gas processing, and gas distribution operations. We also expect above-average dividend growth over our forecast period. Management continues to focus its efforts on increasing the company's competitiveness within its natural gas operations, which should ensure its ongoing viability as well as decrease risk to shareholders. The Power Purchase Arrangements covering its regulated electric generation should provide the company with an attractive, low risk allowed return over the next 20 years. Further, CU announced a number of new independent power initiatives that provides upside to our earnings estimates in light of high electric rates in the province. We believe that CU offers investors lower risk than most of its Canadian gas & electric utility peers.

POWER EXPOSURE IN ALBERTA

Canadian Utilities is exposed to power prices in Alberta through its direct interest in four plants. The Primrose, Poplar Hill and Rainbow Lake power plants have an estimated combined merchant capacity of 65-70 megawatts. The Joffre plant is reported to have an additional 208 megawatts of merchant capacity.

In addition to its ownership in independent power plants with available merchant capacity, Canadian Utilities participated in Alberta's second auction of one-year Power Purchase Arrangements. However, the amount of power purchased by Canadian Utilities under the PPAs has not been disclosed.

INDEPENDENT POWER PLANTS

The following table provides a summary of the company's independent power plants in Alberta that are currently operational, under construction or under development.

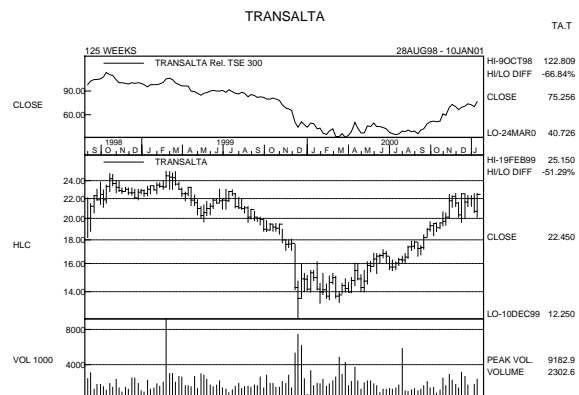
Independent Power Plant	Ownership Interest	Location	Capacity (megawatts)
Primrose Cogeneration Project	40% (a)	Northeast, Alta.	85
Poplar Hill Power Station	80% (b)	Grande Prairie, Alta.	43
Rainbow Lake, Alberta	80% (d)	Rainbow Lake, Alta.	43
Joffre Cogeneration Plant	32% (c)	Joffre, Alta.	416
Scotford Cogeneration Plant (2)	100%	Fort McMurray, Alta.	150
Muskeg River (1)	80%	Fort McMurray, Alta.	170

Notes: (1) Under development; (2) Under construction;
(a) ATCO holds 10% interest; (b) ATCO holds 20% interest; (c) ATCO holds 8% interest; (d) ATCO holds 20% interest

TRANSALTA CORP.

TSE - TA - \$22.45

Stock Rating (Recommendation)	4 (UNDERPERFORM)			1 Yr. Target	\$21.75
Industry Rating	2 (MARKETPERFORM)			Annual Return	1.3%
Shares Outstanding Basic (MM)	168.9				
Float (MM)	168.9				
Market Capitalization (\$MM)	\$3,791.8				
Value of Float (\$MM)	\$3,791.8				
Year End	Dec. 31				
52-Week Price Range	\$13.20-\$22.55				
Debt/Total Capital	0.43				
Dividend	\$1.00	Yield	4.5%		
EPS (\$)	1999	2000E	2001E	2002E	
	0.79	0.93	1.10	1.10	
P/E (X)	28.4	24.1	20.4	20.4	



INVESTMENT ATTRIBUTES

TransAlta Corp. is the largest owner/operator of electric generation facilities in Alberta. It also owns regulated electric transmission facilities in Alberta, and generation facilities in Ontario, Australia and the United States. TransAlta's strategy is to focus its growth and investments in global generation and transmission businesses.

INVESTMENT OUTLOOK

TransAlta completed the sale of its TransAlta New Zealand operations in March 2000 and closed the sale of its Alberta-based electric distribution assets at the end of August. Combined, these sales provided TransAlta with approximately \$1.3 billion in cash proceeds, which the company will redeploy in non-regulated and international investments. Due to the competitive nature of these new endeavours, we believe that the company's risk profile will increase materially going forward. We continue to view TransAlta as expensive from an earnings perspective. The stock is ranked 4 (UNDERPERFORM).

POWER EXPOSURE IN ALBERTA

In Alberta, TransAlta has some availability of merchant power through its ownership positions in the Syncrude, Fort Saskatchewan and Suncor power plants. Further, management believes it will be able to outperform the targets set for its power plants covered by the Power Purchase Arrangements,

providing the company with additional power to sell on the spot market. While the breakdown of the power available from each of the above sources was not provided, the company estimates that it will have approximately 200 megawatts of merchant capacity in Alberta.

Although this report primarily focuses on Alberta's power markets, TransAlta has a large merchant exposure in Washington State where, through its ownership of the Centralia power plant, the company has approximately 114 megawatts of merchant capacity available.

In addition to its ownership in independent power plants with available merchant capacity, TransAlta participated in Alberta's second auction of one-year Power Purchase Arrangements. However, the amount of power purchased by TransAlta under the PPAs has not been disclosed.

INDEPENDENT POWER PROJECTS

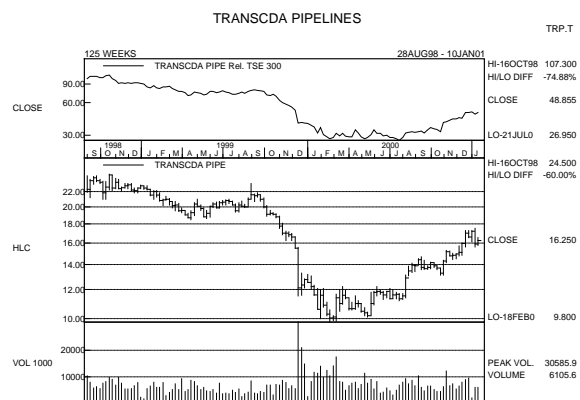
The following table provides details on TransAlta's independent power plants in Alberta.

Independent Power Plant	Ownership Interest	Location	Capacity (megawatts)
Syncrude Power Plant	100%	Fort McMurray, Alta.	265
Fort Sask. Power Plant	60%	Fort Saskatchewan, Alta.	120
Suncor Cogeneration Facility (1)	100%	Fort McMurray, Alta.	360

Notes: (1) Under development

TRANSCANADA PIPELINES**TSE - TRP - \$16.25**

Stock Rating (Recommendation)	2 (OUTPERFORM)			1 Yr. Target	\$20.00
Industry Rating	2 (MARKETPERFORM)			Annual Return	28.0%
Shares Outstanding Basic (MM)	474.6				
Float (MM)	474.6				
Market Capitalization (\$MM)	\$7,712.3				
Value of Float (\$MM)	\$7,712.3				
Major Shareholders	Widely held				
Year End	Dec. 31				
52-Week Price Range	\$9.80-\$17.50				
Debt/Total Capital	0.68				
Dividend	\$0.80	Yield	4.9%		
F.D. EPS (\$)	1999	2000E	2001E	2002E	
P/E (X)	1.04	1.20	1.21	1.34	
	15.6	13.5	13.4	12.1	

**COMPANY PROFILE**

TransCanada PipeLines owns and operates a natural gas transmission pipeline extending from Alberta to Quebec and is affiliated with various Canadian and American pipelines, giving it access to major gas markets. It is also engaged in energy marketing and power generation.

INVESTMENT OUTLOOK

Reflecting our view of a difficult economy over the next 12 months, we recently increased our ranking of TransCanada from 3 (NEUTRAL) to 2 (OUTPERFORM). While there remains concerns with the problems of excess natural gas pipeline supply and the difficulty of renegotiating new incentive-based regulatory agreements, we believe that TransCanada has the capacity to moderately increase its dividend. We also believe there is little downside to our earnings forecast. Our EPS estimates reflect a return on equity tolling methodology on the TransCanada system and the Alberta system. If TransCanada does reach an incentive agreement on either system, we believe there is upside to our earnings estimates.

POWER EXPOSURE IN ALBERTA

TransCanada purchased 560 megawatts of generation capacity during the first Alberta auction held in

August 2000 through its acquisition of the Power Purchase Arrangement covering the Sundance Power plant. However, the company reports that it has largely hedged 450 megawatts through entering long-term supply contracts, leaving 110 megawatts of the Sundance output available for spot sales. Through its ownership of the Redwater and the Carseland power plants, TransCanada also has an additional 42 megawatts of merchant power capacity.

In addition to its ownership in independent power plants with available merchant capacity, TransCanada participated in Alberta's second auction of one-year Power Purchase Arrangements. However, the amount of power purchased by TransCanada under the PPAs has not been disclosed.

INDEPENDENT POWER PLANTS

The table below provides a summary of TransCanada's independent power plants in Alberta that are currently operational, under construction or under development.

Independent Power Plant	Ownership Interest	Location	Capacity (megawatts)
Gold Creek Power Plant	100%	Grande Prairie, Alberta	6
Carseland Power Plant (1)	100%	Carseland, Alberta	80
Redwater Power Plant (1)	100%	Redwater, Alberta	40

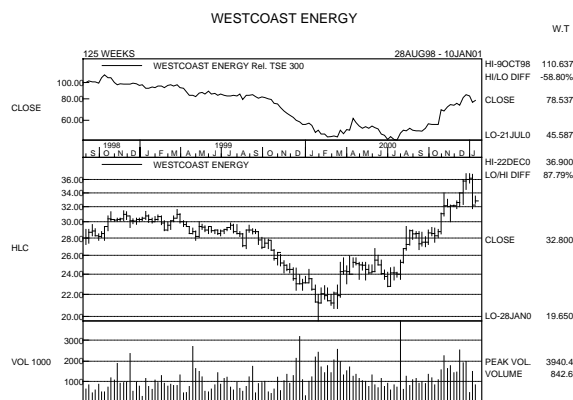
Note: (1) Under development;

WESTCOAST ENERGY*

TSE - W - \$32.80

Stock Rating (Recommendation)	2 (OUTPERFORM)	1 Yr. Target	\$40.00
Industry Rating	2 (MARKETPERFORM)	Annual Return	25.9%

Shares Outstanding Basic (MM)	120.6		
Float (MM)	120.6		
Market Capitalization (\$MM)	\$3,955.7		
Value of Float (\$MM)	\$3,955.7		
Major Shareholders	Widely Held		
Year End	Dec. 31		
52-Week Price Range	\$19.65-\$36.90		
Debt/Total Capital	0.7		
Dividend	\$1.28	Yield	3.9%
	1999	2000E	2001E
EPS (\$)	1.87	2.42	2.54
P/E (X)	17.5	13.6	12.9
		2002E	
		2.64	12.4



* Within the past 12 months, RBC Dominion Securities has undertaken an underwriting liability or has provided advice for a fee with respect to the securities of this company.

COMPANY PROFILE

Westcoast Energy is a diversified company with principal interests in natural gas transmission, gathering and distribution pipelines, marketing of natural gas and power, storage, energy services, power generation and international energy ventures.

INVESTMENT OUTLOOK

Westcoast has a number of strategic investments in energy infrastructure that are uniquely positioned for growth. The company's 37.5% interest in the Maritime and Northeast pipeline provides Westcoast with exposure to further development of the Scotian Shelf natural gas reserves. Its investments in the Fredrickson power plant in Washington State and the Bayside power plant in New Brunswick allow Westcoast to sell electricity into the attractive U.S. Pacific Northwest and Northeast markets. Further, the company's purchase of approximately 300 megawatts of electricity peaking capacity in the Alberta auction of Power Purchase Arrangements provides Westcoast with significant upside due to the high power prices in Alberta. Due to the company's growth opportunities and attractive valuation, we rank it 2 (OUTPERFORM).

POWER EXPOSURE IN ALBERTA

During the August auction of Alberta Power Purchase Arrangements (PPAs), Westcoast acquired the generation output of the Rainbow and Rosedale power plants, providing the company with 296 megawatts of peaking capacity. Although these are gas-fired plants, they are low-efficiency high-cost plants and used only to provide high-cost peaking supply. At an Alberta natural gas price of US\$5.00 per MMBtu, we estimate the cost of power to be C\$125 per MWh. Notwithstanding this high cost of power, we have estimated a net earnings contribution to Westcoast of \$17 million and \$14 million during 2001 and 2002, respectively, from these contracts.

In addition to its Rainbow and Rosedale PPAs, Westcoast participated in Alberta's second auction of one-year Power Purchase Arrangements through its Engage Energy subsidiary. However, the amount of power purchased by Westcoast under the PPAs has not been disclosed.

CONCLUSION

Deregulation of North American electric markets is proving to be more of a challenge than originally contemplated. The tight supply situation, which has been exacerbated by years of regulatory uncertainty, has caused the price of power to spike in the western North American markets that have deregulated. While spiralling power prices have created significant problems for politicians, regulators and customers, for those companies with available merchant generation capacity, there is significant profit potential associated with the current situation. Further, as we do not expect a significant supply response for approximately three years, high power prices in these markets could persist for some time.

Canadian pipeline and gas & electric companies with merchant capacity available to sell into the Alberta spot power market include ATCO, Canadian Utilities, TransCanada, TransAlta and Westcoast. We believe that ATCO and Canadian Utilities have the greatest exposure and upside associated with their merchant capacity.

While demand for power may be inelastic in the short run, in the longer run we expect that plant closures and shutdowns will have an impact on the growth in demand. Further, we believe that there is a material possibility that new power capacity will be over built in Alberta, as well as in Washington, in four to five years.

APPENDIX I – DEREGULATION IN CALIFORNIA**BACKGROUND**

From 1990 to 1995, the price of electricity in California was on average 33% to 42% above the U.S. average. During this period, California's electric industry was regulated by the state and dominated by three large investor-owned utilities (IOUs) – PG&E Corp.'s Pacific Gas & Electric Co., Edison International's Southern California Edison and Sempra Energy's San Diego Gas & Electric. In light of its relatively high cost of electricity, the California Public Utility Commission (CPUC) directed an examination in 1994 into possible alternatives to the cost-of-service regulatory regime. The directive led to a staff report (also known as the "Yellow Book" study) that concluded the state regulatory framework should be reformed. Based on a comprehensive re-examination of the electric utility industry in California, the CPUC developed a strategy (the "Blue Book" proposals) to replace the traditional cost-of-service regulatory framework with a more competitive framework. Greater competition was expected to result in lower retail prices and marketing and technological innovations that would benefit electricity customers. In December 1995, the CPUC issued a final order to restructure the electric power industry and phase-in retail competition.

Assembly Bill 1890 (AB 1890) was enacted on September 23, 1996, which essentially codified many of the elements in the December 1995 CPUC decision. Approved unanimously by the state Senate and the state Assembly, AB 1890 encountered very little opposition. At the time, all three existing IOUs supported the legislation, which allowed for the recovery of their stranded costs. Under the legislation, residential and small commercial users were guaranteed a 10% rate reduction and electric rates were to be frozen for four years. During the transition period, the existing IOUs would be allowed to recover approximately US\$28 billion in stranded costs by charging a "Competition Transition Charge" (CTC). The price of wholesale electricity was also capped at US\$750 per megawatt hour, which at the time many believed would not be reached.

To address concerns about market power, the CPUC ordered the existing IOUs to submit a plan to "voluntarily" divest 50% of their fossil-fuelled generation. As an incentive to voluntarily divest these assets, the CPUC granted an increase in the rate of return for the equity component on the transition cost CTC balancing accounts of up to 10 basis points for each 10% of fossil generating capacity divested. To date, Pacific Gas and Electric has sold 7,401 MW of capacity for US\$1.5 billion, Southern California Edison has sold 10,607 MW for US\$1.2 billion and San Diego Gas & Electric has sold 20,187 MW for US\$3.2 billion. Out-of-state generators, including Duke Energy, Southern Energy, Reliant Energy and NRG Energy, purchased most of the capacity sold by the three IOUs.

To encourage competition in the generation market and prevent the existing IOUs from engaging in monopolistic activities by controlling generation, transmission and distribution, AB 1890 also included provisions for the creation of an independent system operator (ISO) and a legally separate power exchange. The ISO would assume responsibility for ensuring fair and impartial access to the state's transmission grid,

which would continue to be owned by the existing IOUs. The power exchange (PX) would operate an auction market for wholesale electricity. The existing IOUs were required to sell their power to the PX and purchase power from the PX for four years after its inception. This requirement prevented the IOUs from negotiating long-term supply contracts.

On March 31, 1998, California became the first state in the U.S. to open its retail electricity market to competition. Retail customers of the state's three investor-owned utilities were free, for the first time, to choose their electricity supplier. However, customers of the Los Angeles Department of Water and Power and other municipally owned utilities were exempt from deregulation. Control over 70% of the state's transmission system was transferred to the California Independent System Operator and the California Power Exchange commenced trading of wholesale electricity. At that time, California's electric system was expected to serve as a model for other states.

For two years, everything seemed to be functioning properly in California's market. Between April 1, 1998 and May 19, 2000, the average daily price of wholesale electricity on the California Power Exchange was approximately US\$28.50 per MWh. With rates frozen at what then seemed like high levels and the low cost of wholesale electricity, the three IOUs recovered billions of dollars for their stranded costs. Some believed that the benefits of competition would come sooner than under the original deregulation plan. In June 1999, the CPUC approved San Diego Gas & Electric's proposal to end its rate freeze on July 1st. San Diego Gas & Electric was able to end its transition period two and a half years early by recovering all of its stranded costs through the sale of its power plants for an amount substantially above book value. The end of San Diego Gas & Electric's rate freeze was hailed a major "milestone" in California's deregulation effort, as it was expected to result in greater competition and lower prices. Energy marketers complained that the mandatory CTC, which accounted for approximately 40% of retail electric bills, made it impossible for them to offer lower prices.

SUMMER 2000

Unfortunately, a heat wave hit the state in the summer of 2000 that threw the electric system into a crisis. Greater air conditioning usage resulted in increased demand for electricity, also known as load. A booming economy and increased computer usage were also blamed for the higher load. Regardless of the reason, the electric system was unable to cope with the higher load. Thirty-one electric emergency alerts were issued that warned of the possible collapse of the grid and impending blackouts.

Between May 18th and August 31st, the average daily price of wholesale electricity on the California Power Exchange was approximately US\$130 per MWh. The high cost of wholesale electricity was passed on to the customers of San Diego Gas & Electric, who were no longer under the rate freeze. Their electric bills nearly tripled. With reports of pensioners and low-income residents being forced to turn off their refrigerators to conserve electricity, legislation was enacted on September 6th to cap electric rates for San Diego Gas & Electric's customers. Under the cap,

electric rates for San Diego Gas & Electric's residential and small commercial customers would be \$0.065 per kWh through December 31, 2002, retroactive to June 1, 2000.

While customers of Pacific Gas & Electric Co. and Southern California Edison were protected under the rate freeze, both utilities were accumulating significant power purchase losses. Under pressure from Pacific Gas & Electric and Southern California Edison, the ISO lowered the wholesale cap from US\$750 to US\$500 per megawatt hour on June 28, 2000. In August 2000, it lowered the cap again to US\$250. However, the cuts proved to be ineffective. Unlike the summer of 1999, when wholesale prices peaked during the day and declined at night, prices during the same period in 2000 were close to the cap during most of the day and night. Furthermore, the cap did not apply to power purchases, made by the ISO on behalf of the IOUs, from utilities outside of California. Instead of selling their power in California, independent power producers in the state sold power to out-of-state utilities that resold the power back to the ISO at a price above the cap. As well, some Northwest utilities reportedly purchased power from plants owned by Pacific Gas & Electric and Southern California Edison on the California Power Exchange's day-ahead market at US\$250 per megawatt hour and resold it to the utilities through the ISO's real-time market at US\$700 per MWh.

By the end of August, PG&E Corp. reported that it collected US\$2.2 billion less from its customers in the summer than it paid to purchase wholesale electricity on the California Power Exchange. Southern California Edison's deficit at the end of August was US\$2 billion, almost two-thirds of its net worth.

FALL/WINTER 2000

Many believed that California's problems were temporary and would disappear with cooler temperatures. However, prices remained stubbornly high into the fall and winter and several power emergencies were declared in November and December. This time the high prices were blamed on cooler-than-normal weather throughout the U.S. West, high natural gas prices and unplanned power plant outages. Meanwhile, power purchase losses for the three IOUs in California continued to accumulate. Further contributing to the utilities' problems, the ISO unilaterally abandoned the wholesale price cap on December 9th after it realized that generators were withholding power from the state's day-ahead auctions. The generators were doing so with the knowledge that, as the state's buyer of last resort, the ISO would buy power on an emergency basis to avoid blackouts regardless of the cost, which would be passed on to the IOUs. After the cap was lifted, lots of electricity became available but at an average price of approximately US\$450 per MWh.

By the end of 2000, Pacific Gas & Electric incurred an estimated US\$7 billion of undercollected wholesale power costs and Southern California Edison accumulated approximately US\$5 billion during the same time period. In light of these power purchase losses, Pacific Gas & Electric and Southern California Edison threatened to declare bankruptcy unless their electric rates are increased. Under the deregulation legislation, the

rate freeze could not be lifted until the CPUC declared that the utilities' stranded costs had been paid off, which Pacific Gas & Electric and Southern California Edison claim has already happened. As well, credit ratings agencies, including Standard and Poors', threatened to downgrade Pacific Gas & Electric's and Southern California Edison's debt to below investment grade, which would move both utilities closer to bankruptcy. The situation became so dire that the Energy Secretary issued an emergency order requiring generators and marketers to sell electricity to the California market. The order was issued, and subsequently extended, after certain generators were reluctant to sell power into California because of solvency issues surrounding the state's three IOUs. In summary, the power crisis has simply refused to die.

PLACING THE BLAME

Some believe that California's problems are simply an imbalance between supply and demand. While demand has increased by up to 4-5% in some areas, California has added only 672 MW of new generation since 1996 and few plants are slated to go on line until 2002. With the toughest environmental laws in the country, many generators have found it extremely difficult to build new generation. Regulatory uncertainty has also been identified as a deterrent to new construction. In addition, supply has been limited by transmission constraints, especially in northern California.

California's governor and others have charged that the market is being manipulated by generators and energy marketers. They are accusing energy providers of withholding supply to artificially boost the price of power. Several investigations have been launched, including one by the Federal Energy Regulatory Commission (FERC) that found, while prices were high, there wasn't any evidence of market abuse.

Another group believes that the system is fundamentally flawed. Until recently, Pacific Gas & Electric and Southern California Edison were unable to enter into bilateral agreements with generators to hedge against volatile prices in the spot market. Compounding the problem, the utilities have reportedly been underestimating how much power they require the next day. As a result, the California Power Exchange has been forced to purchase power hour by hour as it is needed and electricity purchased at the last minute can be very expensive.

FIXING THE PROBLEM

At this time, FERC appears to belong in the last group. In its recent plan for fixing California's electricity market, the Commission directed market participants to move 95% of transactions in the real-time spot markets into long-term forward contracts. Penalties will be imposed on those that fail to do so. As part of the move away from the spot market, FERC relieved investor-owned utilities from the requirement to purchase and sell through the California Power Exchange. FERC also established a US\$74 per MWh benchmark for five-year energy supply contracts that will be used in the assessment of the fairness and reasonableness of pricing long-term contracts. To facilitate the adoption of forward contracts, a special meeting was convened between utilities, generators and regulators. FERC also established a "soft" cap of US\$150 per MWh. Bids above the US\$150 cap will not be allowed to set the market-clearing price paid to all bidders and will trigger certain reporting

requirements and monitoring. FERC directed its staff to hold a technical conference to develop a comprehensive and systematic monitoring program that is expected to be in place by May 1, 2001. Finally, the Commission ordered that the governing board of California's Independent System Operator (ISO), which is made up of market participants, be replaced with one represented by independent board members.

Deeming FERC's plan for fixing California's electricity market as inadequate, California's governor is holding an emergency session of the state legislature. Several legislative bills designed to give the state more control over its deregulated electric industry are expected to be introduced. The initiatives include: replacing the governing board of California's ISO with a three-member independent board appointed by the governor; creating a public power agency; implementing a windfall profits tax; requiring power suppliers and marketers to register and report all power transactions with the state; and, monitoring power plant outages and maintenance.

In light of their dire financial situation, the California Public Utilities Commission recently approved a temporarily lifting of the freeze on the electric rates of Pacific Gas & Electric and Southern California Edison pending the results of an independent audit of the utilities' financial position. Under the decision, the utilities' rates will be increased by 7% to 15% for a period of 90 days, subject to later refund and adjustment. Rates will be increased by 9% for residential customers, 7% for small businesses, 12% for medium businesses and 15% for large industrial customers. The average rate increase will be approximately 10%, compared to the 26% sought by Pacific Gas and Electric and 30% sought by Southern California Edison. The CPUC also approved a measure to allow Southern California Edison to issue an additional US\$3.5 billion in debt for power purchases. In addition, the Commission reversed its previous decision that required the utilities to transfer US\$1.1 – US\$1.3 billion from each utility's Transition Cost Balancing Account and use the funds to reduce their power purchase shortfalls. The Transition Cost Balancing Account was created under AB 1890 for the recovery of each utilities' stranded costs.

Following the CPUC's interim rate increase decision, credit ratings agencies Standard & Poor's and Moody's Investor Service downgraded the utilities' credit ratings to one level above junk bond ratings. Describing the CPUC decision as "wholly insufficient", Fitch lowered its credit ratings even further to a deeply speculative grade. In light of their liquidity problems, some believe that Pacific Gas & Electric and Southern California Edison could be forced into bankruptcy unless the government is able to find a solution to the growing power crisis.

In his closely-watched annual "State of the State" speech, California's governor recently outlined his proposals designed to address the problems faced by the power industry. Specifically, he rejected the idea that Pacific Gas and Electric and Southern California Edison be allowed to slide into bankruptcy. However, he failed to outline any specific proposals to deal with their immediate financial situation. The governor repeated an earlier promise to allocate US\$1 billion of the state's budget

to help bring new power plants into service and encourage energy conservation. In addition, he recommended that the legislature expand the governor's authority during a state of emergency in the event of imminent power outages. The governor also called for an overhaul of the "crazy bidding" process that guarantees every generator is paid according to the highest bid, instead of their own bid.

Notwithstanding the financial problems of Pacific Gas & Electric and Southern California Edison, consumer advocate groups in California have launched a campaign against CPUC-approved rate increases. The groups have threatened to take legal action against any rate increases, claiming that the CPUC does not have the authority under state legislation to increase retail electricity rates before March 2002, the date when the rate freeze is scheduled to end. The consumer groups also claim that the utilities are overstating their financial woes as profits from generators that the utilities still own can be used to offset one-third to one-half of their wholesale power purchase losses. However, if the utilities do file for bankruptcy, the groups want the state to allow the utilities to go bankrupt rather than conduct a bailout.

APPENDIX II – RESULTS OF ALBERTA'S DECEMBER ELECTRICITY AUCTION

Successful bidders in the sale of balancing pool electricity contracts:

-
- | | |
|---|--|
| 1. Agrium Inc. | 24. EPCOR Energy Services (Alberta) Inc. |
| 2. Anadarko Canada Corporation | 25. EPCOR Utilities Inc. |
| 3. Anderson Exploration Ltd. | 26. Gibson Petroleum Company Limited |
| 4. Aquila Energy Corporation | 27. Gulf Canada Resources Limited |
| 5. ATCO Electric Ltd. | 28. Hudson's Bay Company |
| 6. ATCO Midstream Ltd. | 29. Idaho Power Company |
| 7. Baytex Energy Ltd. | 30. IQ2 Power Corp. |
| 8. BP Canada Energy Company | 31. Magin Energy Inc. |
| 9. Calgary Airport Authority | 32. Numac Energy Inc. |
| 10. Canadian Natural Resources Limited | 33. PanCanadian Petroleum Limited |
| 11. Candela Energy Corporation | 34. Pengrowth Corporation |
| 12. Chevron Canada Resources Limited | 35. Penn West Petroleum Ltd. |
| 13. City of Lethbridge | 36. Petro-Canada |
| 14. Conoco Canada Limited | 37. PG&E Energy Trading-Power, LP |
| 15. Coral Energy Canada Inc. | 38. PrimeWest Energy Inc. |
| 16. Daishowa-Marubeni International Ltd. | 39. Sears Canada Inc. |
| 17. Direct Energy Marketing Limited | 40. Sherritt International Corporation |
| 18. Dow Chemical Canada Inc. | 41. Southern Company Energy Marketing LP |
| 19. Duke Energy Marketing Limited Partnership | 42. Talisman Energy Inc. |
| 20. Dynegy Canada Inc. | 43. TransAlta Energy Marketing Corp. |
| 21. Engage Energy Canada, LP | 44. TransCanada PipeLines Limited |
| 22. ENMAX Energy Corporation | 45. Weyerhaeuser Company Limited |
| 23. Enron Canada Power Corp. | |
-

The information contained in this report has been compiled by RBC Dominion Securities Inc. ("RBCDS-Canada") from sources believed by it to be reliable, but no representations or warranty, express or implied, is made by RBCDS-Canada or any other person as to its accuracy, completeness or correctness. All opinions and estimates contained in this report constitute RBCDS-Canada's judgement as of the date of this report, are subject to change without notice and are provided in good faith but without legal responsibility. This report is not an offer to sell or a solicitation of an offer to buy any securities. RBCDS-Canada and its affiliates may have an investment banking or other relationship with some or all of the issuers mentioned herein and may trade in any of the securities mentioned herein either for their own account or the accounts of their customers. RBCDS-Canada and its affiliates also may issue options on securities mentioned herein and may trade in options issued by others. Accordingly, RBCDS-Canada or its affiliates may at any time have a long or short position in any such security or option thereon. The securities discussed in this report may not be eligible for sale in some states or in some countries. Neither RBCDS-Canada or any of its affiliates, nor any other person, accepts any liability whatsoever for any direct or consequential loss arising from any use of this report or the information contained herein. Any U.S. recipient of this report that is not a registered broker-dealer or a bank acting in a broker or dealer capacity and that wishes further information regarding, or to effect any transaction in, any of the securities discussed in this report, should contact and place orders with RBC Dominion Securities Corporation, a U.S. registered broker-dealer affiliate of RBCDS-Canada, at (212) 858-7019, which, without in any way limiting the foregoing, accepts responsibility (within the meaning, and for the purposes, of Rule 15a-6 under the U.S. Securities Exchange Act of 1934), for this report and its dissemination in the United States. This report may not be reproduced, distributed or published by any recipient hereof for any purpose. **Additional information is available on request.**

RBC DOMINION SECURITIES GLOBAL EQUITY TEAM

P.O. Box 50, Royal Bank Plaza, South Tower, 3rd Floor - Toronto, Ontario, Canada M5J 2W7

Managing Director, Global Equity Wm. W. Moriarty, CFA - Head, Global IE (416) 842-6020	Oil & Gas Brian Kostreba, CA, CFA (Associate) (403) 299-6958 Brock Winterton, CFA (416) 842-7850 Craig Webster, CA (Associate) (416) 842-7894 Kim Page (403) 299-6986 Derek Mendham, CA, CFA (Associate) (403) 299-6954	Frankfurt, Germany 49-69-959115-0 Gerhard Pfeiffer - <i>Managing Director</i> Peter Heer, Marcus Rohrbach
GLOBAL EQUITY RESEARCH Phone: (416) 842-7800, Fax: (416) 842-7810	Paper & Forest Products David Smyth, CFA (604) 257-7660 Nick Szucs (Associate) (604) 257-7657	Lausanne, Switzerland 41-21-310-24-24 Jean Claude Blanc - <i>Managing Director</i> Hans Tschanz, <i>Manager</i> , Mario Castracane, Pascal Despont, Walter Nussbaumer, Aldo Schorno Carl Burgin, Patrice Filiatrault, CFA
Managing Director James McLeod, CFA (416) 842-7819 Ann Bui (Executive Assistant) (416) 842-7803	Real Estate Neil Downey, CA, CFA (416) 842-7835 Joseph Leinwand, CFA (416) 842-7817	London, England 44-20-7-489-8375 Stephen Foss - <i>Managing Director Equities</i> Brian Williamson, Ben Turner, Daniel Holland Simon Catt, Gary Docherty, Robert Keene, CFA
Associate Director Doug Raymond (416) 842-7832	Small Caps/Special Sits Nick Morton, CFA (416) 842-7833 Nadi Tadros (Associate) (416) 842-7893 Jon Reider (514) 878-7790 Jessy Hayem, CFA (Associate) (514) 878-7256	Montreal Steve Foley, CFA - <i>Manager</i> (514) 878-7780 Milla Craig (514) 878-7778
Business Manager Anne Baumann (416) 842-7821 Ann Bui (Executive Assistant) (416) 842-7803	Technology Hardware John Wilson (416) 842-7908 Rui Cardoso (Associate) (416) 842-3807 Stephanie Coriat (Associate) (514) 878-7490	New York Gavin Ezekowitz - <i>Manager</i> (212) 858-7331 Joseph Chiapetta (212) 858-7332 Michael Letros, CFA (212) 858-7381 Brian Smith (212) 858-7334 James Whitecross (212) 858-7382 Andrea T. Bobkowitz (212) 858-7297
Chief Strategist & Managing Director Capital Markets Research Daniel E. Chornous, CFA (416) 842-7805 Sarah Rguem (Associate) (416) 842-8745 Burak Isyar (Assistant) (416) 842-5337	Software Steven Arthur (416) 842-7844 Jonathan Wong (Associate) (416) 842-5338	New York Trend & Cycle (212) 858-7064 Neil MacLennan (212) 858-7060, Paul Funari (212) 858-7062, Bill Vasilakos (212) 858-7063
FUNDAMENTAL RESEARCH	Software & E-Commerce David Beck (416) 842-7841 Cherilyn Radbourne, CA (Associate) (416) 842-3804 David Wai, CFA (Associate) (416) 842-7879	Paris, France 33-1-53-53-33-82 Alain Corbani - <i>Manager</i> , Jean-Phillippe Bry
Biotech/Pharmaceuticals Doug Miehm (416) 842-7823 Kim Lee (Associate) (416) 842-7899	Telecommunications Services	Tokyo 81-3-3589-7600 Kunihiko Nakayama
Chemicals & Fertilizers Mario Jelic, CFA (416) 842-7891	Wireless Jean-François Bergeron (514) 878-7252 Christopher Keene (Associate) (514) 878-7504	Toronto Bernie Allion (416) 842-6053 Peter McKergow (416) 842-6051 Gerry McLeod, CFA (416) 842-6056 Jim Dale, CFA (416) 842-6052 Kelly Gray, CFA (416) 842-6054 Brent Wichenko (416) 842-6085 Lara Zink (416) 842-6057 Don Ritchie (416) 842-6063 Robert Lee (416) 842-6087
Communications & Media Andrea Horan, CFA (416) 842-7857 Drew McReynolds, CA, CFA (Associate) (416) 842-3805	Wireline & Cable Richard E. Talbot, CA, CFA (416) 842-7846 Shawn Nodder, CA, CFA (Associate) (416) 842-3806 Jennifer S. Dainty (Associate) (416) 842-7838	Vancouver Jim McGovern (604) 257-7755
Conglomerates Joseph Leinwand, CFA (416) 842-7817	Transportation/Environmental Services Nick Morton, CFA (416) 842-7833 Nadi Tadros (Associate) (416) 842-7893	GLOBAL EQUITY TRADING
Consumer Products Irene Nattel (514) 878-7262 Martin Gravel (Associate) (514) 878-7264	Fixed Income Credit Nigel Heath (416) 842-6461 Sunil Shah, CFA (416) 842-6466 Anil Passi, CA, CFA (416) 842-6460	Head of Trading Greg Mills (416) 842-6000
Electric & Gas Utilities & Pipelines Maureen E. Howe (604) 257-7195 Fai Lee, CGA (Associate) (604) 257-7662	CAPITAL MARKETS RESEARCH	London, England/International Ninian Stott 44-20-7-489-8372 Rory Butler 44-20-7-489-8372 Steven Hill 44-20-7-653-4545
Financial Services	Economics John Johnston (Chief Economist - Americas) (416) 842-6631 David Wolf (Senior Economist) (416) 842-6632 Beata Caranci (Associate) (416) 842-6630 Ian Beauchamp (Chief Economist - Europe) -44-171-653-4865 Su-Lin Ong (Senior Economist - Aus/NZ) 011-612-9373-0890	Montreal Raymond Chevalier (514) 878-7774 Arthur Broniszewski (514) 878-7776 Lee Grant (514) 878-7792
Banks Melanie Ward, CFA (416) 842-7848 Darko Mihelic, CFA (Associate) (416) 842-7804	Quantitative Research Darwin McGrath, CFA (416) 842-7866 Andrew Marsden (Assistant) (416) 842-7883	New York (212) 858-7040 Catherine Carr, Mike Cioffi, David Greenhalgh, Andre Jonker, Maryanne Saunders, Richard A. Sorrentino
Non-Bank Financial Services Tom Jarmai (416) 842-7815 Walter Spracklin (Associate) (416) 842-7877	Trend & Cycle Ray Hanson (Canada) (416) 842-8747 Robert Sluymer, CFA (U.S.) (212) 858-7066 Nadine Eugene (Assistant) (416) 842-8744	Toronto Andrew Foote, CFA, Manager Liability Trading (416) 842-6000 James Beattie CFA, Dan Bradley, Campbell Craig, Anthony Cox, Jeff Fields, Derek Flood, Tom Gajer, CFA, Graham MacKenzie, Peter Newell, Sean Riley, Matt Skipp, Rachel Thurley, Jackie Walker, David Wood
Insurance Tom Jarmai (416) 842-7815 Katia Ivanova (Associate) (416) 842-3803	GLOBAL EQUITY SALES	Vancouver Mike Rowley (604) 257-7777 Patrick Granger (604) 257-7551
Gold & Precious Metals	Managing Director David Fowler (416) 842-6050	
North American Precious Metals Kevin MacLean, CFA (416) 842-7854 Stephen D. Walker (416) 842-4120 Derek Tucker (Associate) (416) 842-5339	Boston Tim Brown, CFA - <i>Managing Director</i> (617) 482-2640 Andrew Grimes (617) 482-2353	
Global Gold & Diamonds John Barker 44-207-653-4600 David Walsh (Associate) 44-207-653-4603 Jacquie Clifton (Assistant) 44-207-653-4590	Calgary Katie Trafford, CFA (403) 299-6992	
Income Trusts Petro Panarites, CFA (416) 842-7840 Mary Susan McKee (Associate) (416) 842-7915		
Industrial Products Michael Lam (416) 842-7808		
Merchandising Irene Nattel (514) 878-7262 Jennifer Aitken (Associate) (514) 878-7258		
Mines/Metals G. E. Nutter (416) 842-7859 Cliff Hale-Sanders (416) 842-7892 Jed Richardson (Associate) (416) 842-7861 Josie Cuttorelli (Assistant) (416) 842-7802		