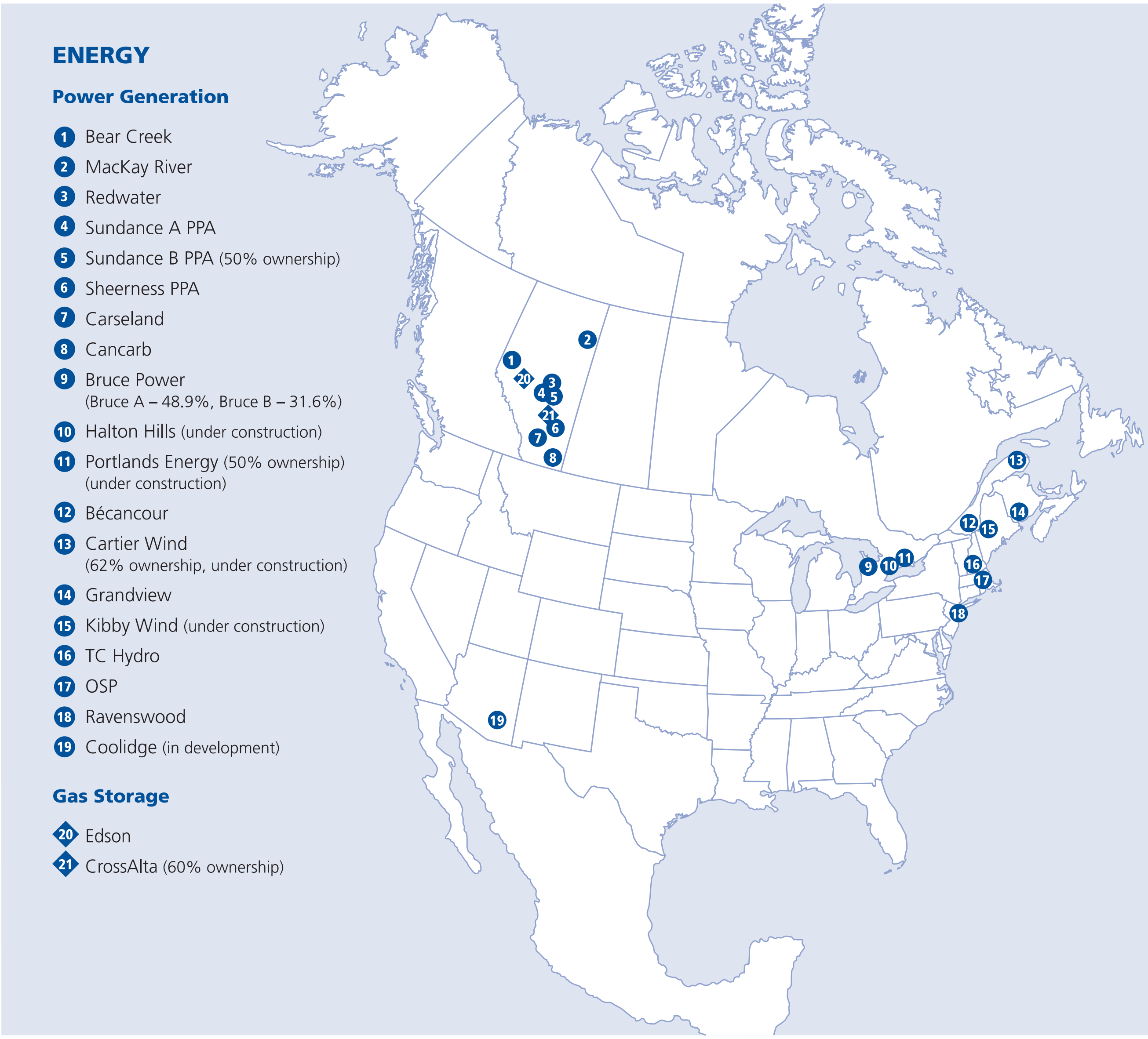


BEAR CREEK An 80 MW natural gas-fired cogeneration plant, Bear Creek is located near Grande Prairie, Alberta.

MACKAY RIVER A 165 MW natural gas-fired cogeneration plant, MacKay River is located near Fort McMurray, Alberta.

REDWATER A 40 MW natural gas-fired cogeneration plant, Redwater is located near Redwater, Alberta.

SUNDANCE A&B TransCanada has the rights to 100 per cent of the generating capacity of the 560 MW Sundance A coal-fired power generating facility under a PPA, which expires in 2017. TransCanada also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a PPA that expires in 2020. The Sundance facilities are located in south-central Alberta.

SHEERNESS TransCanada has the rights to 756 MW of generating capacity from the Sheerness coal-fired plant under a PPA, which expires in 2020. The Sheerness plant is located in southeastern Alberta.

CARSELAND An 80 MW natural gas-fired cogeneration plant, Carseland is located near Carseland, Alberta.

CANCARB A 27 MW facility fuelled by waste heat from TransCanada's adjacent thermal carbon black (a natural gas by-product) facility, Cancarb is located in Medicine Hat, Alberta.

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.9 per cent of Bruce A, which has four 750 MW reactors, two of which are currently being refurbished and are expected to restart in 2010. TransCanada owns 31.6 per cent of Bruce B, which has four operating reactors with a combined capacity of approximately 3,200 MW.

HALTON HILLS A 683 MW natural gas-fired power plant, Halton Hills is under construction near the town of Halton Hills, Ontario, and is expected to be in service in third quarter 2010.

PORTLANDS ENERGY A 550 MW high-efficiency, combined-cycle natural gas generation power plant, Portlands Energy is under construction near the downtown area of Toronto, Ontario. The plant is 50 per cent owned by TransCanada and is expected to be commissioned in its combined-cycle mode in first quarter 2009.

BÉCANCOUR A 550 MW natural gas-fired cogeneration power plant, Bécancour is located near Trois-Rivières, Québec.

CARTIER WIND The 740 MW Cartier Wind farm consists of six wind power projects located in Québec. Cartier Wind is 62 per cent owned by TransCanada. Three of the projects, Baie-des-Sables, Anse-á-Valleau and Carleton have generating capacities of 110 MW, 101 MW and 109 MW, respectively. Planning and construction of the remaining three projects will continue, subject to future approvals.

GRANDVIEW A 90 MW natural gas-fired cogeneration power plant, Grandview is located in Saint John, New Brunswick.

KIBBY WIND The 132 MW Kibby Wind power project is under construction and will include 44 turbines located in Kibby and Skinner Townships in Maine. Construction began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

TC HYDRO With a total generating capacity of 583 MW, TC Hydro comprises 13 hydroelectric facilities, including stations and associated dams and reservoirs, on the Connecticut and Deerfield rivers in New Hampshire, Vermont and Massachusetts.

OSP A 560 MW natural gas-fired, combined-cycle facility, OSP is located in Burrillville, Rhode Island.

RAVENSWOOD In August 2008, TransCanada acquired the 2,480 MW multiple unit generating facility in Queens, New York employing dual-fuel capable steam turbine, combined cycle and combustion turbine technology.

COOLIDGE A 575 MW simple-cycle, natural gas-fired peaking power generation station, Coolidge is under development in Coolidge, Arizona. Detailed engineering, geotechnical and regulatory work began in 2008 and commissioning of the facility is expected in 2011.

EDSON An underground natural gas storage facility, Edson is connected to the Alberta System near Edson, Alberta. The facility's central processing system is capable of maximum injection and withdrawal rates of 725 mmcf/d of natural gas. Edson has a working natural gas storage capacity of approximately 50 Bcf.

CROSSALTA An underground natural gas storage facility, CrossAlta is connected to the Alberta System and is located near Crossfield, Alberta. TransCanada owns 60 per cent of CrossAlta, which has a working natural gas capacity of 54 Bcf with a maximum capability of delivering 480 mmcf/d.

ENERGY – HIGHLIGHTS

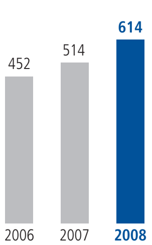
- Energy's net earnings were $614 million in 2008, an increase of $100 million from $514 million in 2007. Energy's comparable earnings were $641 million in 2008, an increase of $182 million from $459 million in 2007.
- In August 2008, TransCanada acquired the 2,480 MW Ravenswood facility in Queens, New York for US$2.9 billion, subject to certain post-closing adjustments.
- Approximately 2,700 MW of additional generation capacity was under construction at December 31, 2008, with an anticipated capital cost of $5 billion.
- Since 1999, the nominal generating capacity of TransCanada's Energy business has increased by approximately 7,800 MW, representing an investment of approximately $7 billion to the end of 2008, with an additional 2,700 MW currently under development and construction.

ENERGY RESULTS
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Western Power	**426**	308	297
Eastern Power	**338**	255	187
Bruce Power	**201**	167	235
Natural Gas Storage	**135**	136	93
General, administrative, support costs and other	**(168)**	(158)	(144)
Operating income	**932**	708	668
Financial charges	**(23)**	(22)	(23)
Interest income and other	**6**	10	5
Income taxes	**(274)**	(237)	(221)
Comparable Earnings(1)	**641**	459	429
Writedown of Broadwater costs	**(27)**	–	–
Gain on sale of land	**–**	14	–
Fair value adjustments of natural gas storage inventory and forward contracts	**–**	7	–
Income tax adjustments	**–**	34	23
Net Earnings	**614**	514	452

(1) Refer to the "Non-GAAP Measures" section of this MD&A for further discussion of comparable earnings.

Energy Net Earnings
(millions of dollars)



Energy's net earnings in 2008 of $614 million increased $100 million compared to $514 million in 2007. Comparable earnings of $641 million in 2008 increased $182 million compared to 2007 and excluded a $27 million writedown of costs previously capitalized for Broadwater. The increases in comparable and net earnings were due to higher operating income in Western Power, Eastern Power and Bruce Power. Comparable earnings of $459 million for 2007 excluded net unrealized gains of $7 million resulting from changes in fair value of proprietary natural gas storage inventory and natural gas forward purchase and sale contracts, a $14 million gain on sale of land and $34 million of favourable income tax adjustments.

Energy's net earnings in 2007 were $514 million compared to $452 million in 2006. Comparable earnings were $459 million in 2007, an increase of $30 million from 2006. The increase was due to higher operating income in Eastern Power, Natural Gas Storage and Western Power, partially offset by a reduced contribution from Bruce Power. Comparable earnings excluded net unrealized gains of $7 million resulting from natural gas storage fair value changes, a $14 million gain on sale of land, $34 million of favourable income tax adjustments in 2007 as well as a $23 million favourable impact in 2006 from future income taxes as a result of reductions in Canadian federal and provincial corporate income tax rates.

POWER PLANTS – NOMINAL GENERATING CAPACITY AND FUEL TYPE

	MW	Fuel Type
Western Power		
Sheerness	756	Coal
Coolidge(1)	575	Natural gas
Sundance A	560	Coal
Sundance B(2)	353	Coal
MacKay River	165	Natural gas
Carseland	80	Natural gas
Bear Creek	80	Natural gas
Redwater	40	Natural gas
Cancarb	27	Natural gas
	2,636	
Eastern Power		
Ravenswood(3)	2,480	Natural gas/oil
Halton Hills(1)	683	Natural gas
TC Hydro	583	Hydro
OSP	560	Natural gas
Bécancour	550	Natural gas
Cartier Wind(4)	458	Wind
Portlands Energy(5)	275	Natural gas
Kibby Wind(1)	132	Wind
Grandview	90	Natural gas
	5,811	
Bruce Power(6)	2,480	Nuclear
Total nominal generating capacity(1)	10,927	

(1) Halton Hills and Kibby Wind are currently under construction. Coolidge is currently under development.
(2) Represents TransCanada's 50 per cent share of the Sundance B power plant output.
(3) Acquired in third quarter 2008.
(4) Represents TransCanada's 62 per cent share of the total 740 MW project. Three of six wind farms were placed in service, one in November 2008, one in November 2007 and the other in November 2006, with a combined generating capacity of 320 MW.
(5) Represents TransCanada's 50 per cent share of this 550 MW facility, which is currently under construction.
(6) Represents TransCanada's 48.9 per cent proportionate interest in Bruce A and 31.6 per cent proportionate interest in Bruce B.

ENERGY – FINANCIAL ANALYSIS

Western Power

As at December 31, 2008, Western Power owns or has the rights to approximately 2,600 MW of power supply in Alberta and the western U.S. from its three long-term power purchase arrangements (PPA), six natural gas-fired cogeneration facilities and a peaking facility under development in Arizona. The power supply portfolio of Western Power in Alberta comprises approximately 1,700 MW of low-cost, base-load coal-fired generation supply through the three long-term PPAs and approximately 400 MW of natural gas-fired cogeneration assets. This supply portfolio includes some of the lowest cost, most competitive generation in the Alberta market area. The Sheerness and Sundance B PPAs have remaining terms of 12 years, while the Sundance A PPA has a remaining term of nine years. In 2008, the Salt River Project Agricultural Improvement and Power District (Salt River Project), a utility based in Phoenix, Arizona, entered into a 20-year PPA to secure 100 per cent of the output from TransCanada's planned Coolidge generating station. The simple-cycle natural gas-fired peaking power facility to be located in Coolidge, Arizona is expected to be commissioned in 2011 and have a nominal generating capacity of 575 MW.

Western Power relies on its two integrated functions, marketing and plant operations, to generate earnings. The marketing function, based in Calgary, Alberta, purchases and resells electricity sourced from the PPAs, markets uncommitted volumes from the cogeneration facilities, and purchases and resells power and natural gas to maximize the value of the cogeneration facilities. The marketing function is integral to optimizing Energy's return from its portfolio of power supply and to managing risks associated with uncontracted volumes. A portion of Energy's power is sold into the spot market for operational reasons and the amount of supply volumes eventually sold into the spot market is dependent upon the ability to transact in forward sales markets at acceptable contract terms. This approach to portfolio management helps to minimize costs in situations where TransCanada would otherwise have to purchase electricity in the open market to fulfil its contractual sales obligations. To reduce exposure to spot market prices on uncontracted volumes, Western Power had, as at December 31, 2008, fixed-price power sales contracts to sell approximately 8,800 gigawatt hours (GWh) in 2009 and 5,500 GWh in 2010.

Plant operations in Alberta consist of five natural gas-fired cogeneration power plants with an approximate combined output capacity of 400 MW ranging from 27 MW to 165 MW per facility. A portion of the expected output is sold under long-term contracts and the remaining output is subject to fluctuations in the price of power and natural gas. Market heat rate is an economic measure for natural gas-fired power plants and is determined by dividing the average price of power per megawatt hour (MWh) by the average price of natural gas per GJ for a given period. To the extent power is not sold under long-term contracts and plant fuel gas has not been purchased under long-term contracts, the profitability of a natural gas-fired generating facility rises in proportion to an increase in the market heat rate and declines in proportion to a decrease in the market heat rate. Market heat rates in Alberta increased in 2008 by approximately six per cent as a result of an increase in average power prices, partially offset by an increase in spot market natural gas prices. Market heat rates averaged approximately 12.05 GJ/MWh in 2008 compared to approximately 11.40 GJ/MWh in 2007.

Western Power's plants operated with an average plant availability of approximately 87 per cent in 2008 compared to 90 per cent in 2007. The decrease was primarily due to an extended outage at the Cancarb power plant.

Western Power Results
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Revenues			
Power	**1,140**	1,045	1,185
Other(1)	**130**	89	169
	1,270	1,134	1,354
Commodity purchases resold			
Power	**(575)**	(608)	(767)
Other(2)	**(64)**	(65)	(135)
	(639)	(673)	(902)
Plant operating costs and other	**(180)**	(135)	(135)
Depreciation	**(25)**	(18)	(20)
Operating income	**426**	308	297

(1) Other revenue includes sales of natural gas, sulphur and thermal carbon black.
(2) Other commodity purchases resold includes the cost of natural gas sold.

Western Power Sales Volumes
Year ended December 31 *(GWh)*

	2008	2007	2006
Supply			
Generation	**2,322**	2,154	2,259
Purchased			
Sundance A & B and Sheerness PPAs	**12,368**	12,199	12,712
Other purchases	**807**	1,433	1,905
	15,497	15,786	16,876
Contracted vs. Spot			
Contracted	**11,284**	11,998	12,750
Spot	**4,213**	3,788	4,126
	15,497	15,786	16,876

Operating income was $426 million in 2008, an increase of $118 million from $308 million in 2007. The increase was primarily due to increased margins from a combination of higher overall realized power prices and market heat rates on uncontracted volumes of power sold, as well as a $23 million increase from sales of sulphur at significantly higher prices in 2008. In 2008, the Company sold the remainder of its sulphur stock pile, which it has been selling in modest quantities on a break-even basis since 2005.

Revenues increased in 2008 primarily due to the higher overall power sales prices. Commodity purchases resold decreased in 2008 compared to 2007 primarily due to a decrease in volumes purchased and the expiry of certain retail contracts. Plant operating costs and other, which includes fuel gas consumed in generation, increased in 2008 as a result of higher volumes of gas purchased at higher prices. Purchased power volumes in 2008 decreased primarily due to the expiry of certain retail contracts, partially offset by increased utilization from the Alberta PPAs. Approximately 27 per cent of power sales volumes were sold in the spot market in 2008 compared to 24 per cent in 2007.

Operating income was $308 million in 2007, an increase of $11 million from $297 million in 2006. The increase was primarily due to lower PPA costs, partially offset by slightly lower overall realized power prices. Revenues decreased in 2007 compared to 2006 due mainly to the lower overall power sales prices realized in 2007 as well as lower volumes purchased and generated. Commodity purchases resold decreased in 2007 compared to 2006 primarily due to lower PPA costs, a decrease in volumes purchased and the expiry of certain retail contracts. Purchased power volumes in 2007 decreased compared to 2006 mainly as a result of an increase in outage hours at the Sundance A facility and the expiry of certain retail contracts. Approximately 24 per cent of power sales volumes were sold into the spot market in 2007, which was consistent with 2006.

Eastern Power

Eastern Power owns approximately 5,800 MW of power generation capacity, including facilities under construction or in the development phase. Eastern Power's current operating power generation assets are Ravenswood, TC Hydro, OSP, Bécancour, the Cartier Wind farms and Grandview. Ravenswood, acquired in August 2008, is a 2,480 MW gas and oil-fired generating facility consisting of multiple units employing steam turbine, combined-cycle and combustion turbine technology. Ravenswood, located in Queens, has the capacity to serve approximately 21 per cent of the overall peak load in New York City. The TC Hydro assets include 13 hydroelectric stations housing a total of 39 hydroelectric generating units in New Hampshire, Vermont and Massachusetts.

OSP, a natural gas-fired combined-cycle facility, is the largest power plant in Rhode Island. Bécancour, a natural gas-fired cogeneration plant located near Trois Rivières, Québec, was placed into service in September 2006. The entire power output is supplied to Hydro-Québec under a 20 year power purchase contract. Steam from this facility is sold to an industrial customer for use in commercial processes. Cartier has a combined generating capacity of 320 MW and consists of three wind farms, Carleton, Anse-á-Valleau, and Baie-des-Sables, which were placed into service in November 2008, November 2007 and November 2006, respectively. Output from these three wind farms is supplied to Hydro-Québec under 20 year power purchase contracts. Grandview is a natural gas-fired cogeneration facility on the site of the Irving Oil Refinery (Irving) in Saint John, New Brunswick. Under a 20 year tolling arrangement which will expire in 2025, Irving supplies fuel for the plant and contracts for 100 per cent of the plant's heat and electricity output.

Eastern Power conducts its business primarily in the deregulated New England and New York power markets and in Eastern Canada. In the New England market, TransCanada has established a marketing operation through its wholly owned subsidiary, TransCanada Power Marketing Ltd. (TCPM). TCPM is located in Westborough, Massachusetts, and effective January 1, 2009, also markets the output from the Ravenswood facility. To reduce exposure to spot market prices on uncontracted volumes, Eastern Power had, as at December 31, 2008, fixed price sales contracts to sell forward approximately 13,000 GWh in 2009 and 15,000 GWh in 2010, although certain contracted volumes are dependant on customer usage levels. Actual amounts contracted in future periods will depend on market liquidity and other factors. Fixed price sales contracts in 2009 exclude approximately 4,300 GWh of generation from the Bécancour power plant as a result of a suspension of electricity generation that began in January 2008 and continues through December 2009. The suspension of the Bécancour power facility is discussed further in the "Energy – Opportunities and Developments" section of this MD&A.

TCPM focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers while managing a portfolio of power supplies sourced from both its own generation and wholesale power purchases. In 2008, TCPM continued to expand its marketing presence and customer base in the New England market.

The Forward Capacity Market (FCM) in the New England power pool is intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Under the FCM, Independent System Operator New England (ISO-NE) projects the needs of the power system three years in advance, following which it holds an annual auction to purchase power resources to satisfy future needs. Prior to the auction period, certain transition payments are made to capacity suppliers in New England that were in existence at June 2006.

ISO-NE has undertaken two Forward Capacity Auctions (FCA) under the FCM framework for procurement of installed capacity; FCA1 for the 2010-2011 period and FCA2 for the 2011-2012 period. All of Eastern Power's existing and planned power assets in the New England market were entered into both FCA1 and FCA2. Both auctions resulted in significant amounts of qualifying capacity resulting in decreased prices. The clearing prices in these auctions were US$4.25 and US$3.12 per kilowatt-month, respectively. Future auction results will be affected by actual demand growth and the pace of progress in the development of new qualifying resources that bid into these auctions, as well as other factors.

The New York Independent System Operator (NYISO) relies on a locational capacity market intended to promote investment in new and existing power resources needed to meet growing consumer demand and maintain a reliable power system. Currently, a series of voluntary forward auctions and a mandatory spot demand curve price setting process is used to determine the price that is paid to capacity suppliers. There are separate demand curves for each of the three capacity zones: Long Island, New York City and the rest of the state. Ravenswood's capacity is located in the New York City capacity zone. Energy and capacity prices for Ravenswood are affected by circumstances that have an impact on supply and demand within this zone, certain NYISO market rules impacting both buyers and suppliers of capacity in this zone, and certain reliability criteria set out by the NYISO and the New York State Reliability Council. There is currently surplus capacity within this zone, however, TransCanada expects capacity will tighten after 2009 as a result of the expected retirement of a power station owned by the New York Power Authority.

Eastern Power Results[1]
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Revenues			
Power	**1,254**	1,481	789
Other[2]	**350**	239	292
	1,604	1,720	1,081
Commodity purchases resold			
Power	**(519)**	(755)	(379)
Other[3]	**(324)**	(208)	(257)
	(843)	(963)	(636)
Plant operating costs and other	**(342)**	(454)	(226)
Depreciation	**(81)**	(48)	(32)
Operating income	**338**	255	187

(1) Includes Carleton, Ravenswood, Anse-à-Valleau, Baie-des-Sables and Bécancour effective November 2008, August 2008, November 2007, November 2006 and September 2006, respectively.

(2) Other revenue includes sales of natural gas.

(3) Other commodity purchases resold includes the cost of natural gas sold.

Eastern Power Sales Volumes[1]
Year ended December 31 *(GWh)*

	2008	2007	2006
Supply			
Generation	**5,043**	8,095	4,700
Purchased	**6,183**	6,986	3,091
	11,226	15,081	7,791
Contracted vs. Spot			
Contracted	**10,990**	14,505	7,374
Spot	**236**	576	417
	11,226	15,081	7,791

(1) Includes Carleton, Ravenswood, Anse-à-Valleau and Baie-des-Sables effective November 2008, August 2008, November 2007 and November 2006, respectively. Bécancour is included in Eastern Power effective September 2006 through December 2007.

Operating income was $338 million in 2008, $83 million higher than the $255 million earned in 2007. The increase was primarily due to increased water flows from the TC Hydro generation assets and higher realized prices on sales to commercial and industrial customers in New England, incremental income from the first full year of operations from the Anse-à-Valleau wind farm and the start-up of the Carleton wind farm in November 2008. On December 31, 2008, Ravenswood fulfilled its obligation under a tolling agreement with Hess Corporation that was in place at the time of acquisition. In 2009, TCPM will manage the marketing output of the Ravenswood plant in a manner consistent with its other U.S. northeast portfolio of assets. The agreement to temporarily suspend generation at the Bécancour facility beginning January 2008 resulted in decreases to power revenues, plant operating costs and other, generation volumes and contracted sales in 2008. The temporary suspension agreement has not materially affected Eastern Power's operating income due to capacity payments received pursuant to the agreement with Hydro-Québec. The agreement to suspend generation at the Bécancour facility was extended for one year to December 31, 2009.

Eastern Power's power revenues were $1,254 million in 2008, a decrease of $227 million from $1,481 million in 2007. This was primarily due to the temporary suspension of generation at the Bécancour facility and decreased sales to commercial and industrial customers in the New England market, partially offset by higher realized prices in New England, increased water flows through the TC Hydro generation assets, and incremental revenue from Ravenswood. Other revenue and other commodity purchases resold increased year-over-year as a result of an increase in the quantity of natural gas purchased and resold under OSP's and TCPM's natural gas supply contracts. Power commodity purchases resold and purchased power volumes were lower in 2008 due to the impact of decreased sales volumes to commercial and industrial customers, lower overall cost per GWh on purchased power volumes and increased power generation from the TC Hydro assets, which reduced the requirement to purchase power to fulfill contractual sales obligations. Plant operating costs and other, which includes fuel gas consumed in generation, were lower in 2008 primarily due to the temporary suspension of generation at the Bécancour facility, partially offset by incremental operating costs from Ravenswood.

Operating income was $255 million in 2007, $68 million higher than the $187 million earned in 2006. The increase was primarily due to incremental income from the first full year of operations from the Bécancour facility and the Baie-des-Sables wind farm, as well as the start-up of the Anse-à-Valleau wind farm in November 2007. Also contributing to the increase were payments received under the start-up of the FCM in New England and higher sales volumes to commercial and industrial customers in 2007. Partially offsetting these increases was the impact of reduced water flows from the TC Hydro generation assets in 2007, compared to the above-average water flows experienced in 2006 following higher precipitation in the surrounding area.

Bruce Power

As at December 31, 2008, TransCanada and BPC Generation Infrastructure Trust (BPC), a trust established by the Ontario Municipal Employees Retirement System, each owned a 48.9 per cent interest in Bruce A (2007 – 48.7 per cent). The remaining 2.2 per cent interest in Bruce A is owned by the Power Workers' Union Trust, the Society of Energy Professionals Trust and Bruce Power Employee Investment Trust. The Bruce A partnership subleases Bruce A Units 1 to 4 from the Bruce B partnership. TransCanada continues to own 31.6 per cent of Bruce B, which consists of Units 5 to 8 and the supporting site infrastructure.

The following Bruce Power financial results reflect the operations of six of the eight Bruce Power units:

Bruce Power Results
Year ended December 31 *(millions of dollars)*

	2008	2007	2006
Bruce Power (100 per cent basis)			
Revenues			
Power	**2,064**	1,920	1,861
Other(1)	**96**	113	71
	2,160	2,033	1,932
Operating expenses			
Operations and maintenance(2)	**(1,066)**	(1,051)	(912)
Fuel	**(139)**	(104)	(96)
Supplemental rent(2)	**(174)**	(170)	(170)
Depreciation and amortization	**(151)**	(151)	(134)
	(1,530)	(1,476)	(1,312)
	630	557	620
TransCanada's proportionate share:			
Bruce A (48.9%)	**62**	24	91
Bruce B (31.6%)	**158**	161	137
	220	185	228
Adjustments	**(19)**	(18)	7
TransCanada's operating income from Bruce Power	**201**	167	235
Bruce Power – Other Information			
Plant availability			
Bruce A	**82%**	78%	81%
Bruce B	**87%**	89%	91%
Combined Bruce Power	**86%**	86%	88%
Planned outage days			
Bruce A	**91**	121	81
Bruce B	**100**	93	65
Unplanned outage days			
Bruce A	**27**	17	37
Bruce B	**65**	32	31
Sales volumes (GWh)			
Bruce A – 100 per cent	**10,580**	10,180	10,650
Bruce A – TransCanada's proportionate share	**5,159**	4,959	5,158
Bruce B – 100 per cent	**24,680**	25,290	25,820
Bruce B – TransCanada's proportionate share	**7,799**	7,992	8,159
Combined Bruce Power – 100 per cent	**35,260**	35,470	36,470
TransCanada's proportionate share	**12,958**	12,951	13,317
Results per MWh			
Bruce A power revenues	**$62**	$59	$58
Bruce B power revenues	**$57**	$52	$48
Combined Bruce Power revenues	**$59**	$55	$51
Combined Bruce Power fuel	**$4**	$3	$3
Combined Bruce Power total operating expenses(3)	**$42**	$41	$35
Percentage of output sold to spot market	**23%**	45%	35%

(1) Other revenue includes Bruce A fuel cost recoveries of $61 million in 2008 (2007 – $35 million; 2006 – $30 million). Other revenue also includes unrealized losses of $6 million as a result of changes in fair value of held-for-trading derivatives in 2008 (2007 – $47 million gain; 2006 – nil).

(2) Includes adjustments to eliminate the effects of inter-partnership transactions between Bruce A and Bruce B.

(3) Net of fuel cost recoveries.

TransCanada's operating income from Bruce Power was $201 million in 2008 compared to $167 million in 2007. TransCanada's proportionate share of operating income in Bruce A increased $38 million to $62 million in 2008 compared to 2007 primarily due to higher realized prices and higher volumes associated with a decrease in outage days in 2008. TransCanada's proportionate share of operating income in Bruce B decreased $3 million to $158 million in 2008 compared to 2007 primarily due to higher operating costs and lower volumes associated with an increase in outage days in 2008, and unrealized gains in 2007 from changes in the fair value of power swaps and forwards. Partially offsetting these decreases were higher realized prices reflecting a higher proportion of volumes sold at higher contract prices.

Combined Bruce Power prices, which are based solely on power revenues, were $59 per MWh in 2008 compared to $55 per MWh in 2007, reflecting higher prices on both contracted volumes and uncontracted volumes sold into the spot market. Bruce Power's combined operating expenses (net of fuel cost recoveries) increased to $42 per MWh in 2008 from $41 per MWh in 2007 primarily due to higher operating costs in 2008.

The Bruce units ran at a combined average availability of 86 per cent in 2008, which was consistent with the average availability in 2007.

TransCanada's operating income from its combined investment in Bruce Power was $167 million in 2007 compared to $235 million in 2006. The decrease of $68 million was primarily due to lower output and higher operating costs associated with an increase in planned outage days, partially offset by higher overall realized prices.

Adjustments to TransCanada's interest in Bruce Power's income before income taxes were lower in 2008 and 2007 than in 2006 primarily due to lower positive purchase price amortizations related to the expiry of power sales agreements.

The overall plant availability percentage in 2009 is expected to be in the low 90s for the four Bruce B units and the mid-80s for the two operating Bruce A units. An approximate six week maintenance outage of Bruce B Unit 8 is scheduled to begin in mid-April 2009 and an approximate six week maintenance outage of Bruce B Unit 6 is scheduled to begin in early October 2009. An approximate six week maintenance outage of Bruce A Unit 4 is scheduled to start in early March 2009 and an approximate one-month outage of Bruce A Unit 3 is expected to commence in mid-March 2009.

Bruce A

Income from Bruce A is affected by overall plant availability, which in turn is affected by planned and unplanned maintenance. As a result of a contract with the Ontario Power Authority (OPA), all of the output from Bruce A is effectively sold at a fixed price per MWh, adjusted for inflation annually on April 1. In addition, fuel costs are recovered from the OPA. In accordance with a 2007 contract amendment, effective April 1, 2008, the fixed price for output from Bruce A was $63.00 per MWh, an increase of $2.11 per MWh, subject to inflation adjustments from October 31, 2005.

Bruce A Fixed Price

	per MWh
April 1, 2008 – March 31, 2009	$63.00
April 1, 2007 – March 31, 2008	$59.69
April 1, 2006 – March 31, 2007	$58.63

Support payments received pursuant to the OPA contract are equal to the difference between the fixed prices under the OPA contract and spot market prices and are capped at $575 million for the period ending on the commercial in-service date of the later of the restarted Unit 1 and Unit 2. As at December 31, 2008, Bruce A had received $368 million towards this cap. Post-refurbishment prices will also be adjusted for capital cost variances associated with the refurbishment and restart projects.

Bruce B

Income from Bruce B is directly affected by fluctuations in wholesale spot market prices for electricity and overall plant availability, which in turn is affected by planned and unplanned maintenance.

As part of Bruce Power's contract with the OPA, sales from the Bruce B Units 5 to 8 are subject to a floor price adjusted annually for inflation on April 1.

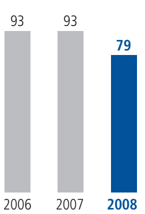
Bruce B Floor Price

	per MWh
April 1, 2008 – March 31, 2009	$47.66
April 1, 2007 – March 31, 2008	$46.82
April 1, 2006 – March 31, 2007	$45.99

Payments received pursuant to the Bruce B floor price mechanism may be subject to a recapture payment dependent on annual spot prices over the term of the contract. Bruce B net earnings to date have not included any amounts received pursuant to this floor mechanism. To further reduce its exposure to spot market prices, as at December 31, 2008, Bruce B had entered into fixed price sales contracts to sell forward approximately 12,460 GWh for 2009 and 7,100 GWh for 2010.

Plant Availability

Power Plant Availability (excluding Bruce Power)
(per cent)



Weighted average power plant availability for all plants, excluding Bruce Power, was 79 per cent in 2008 compared to 93 per cent in 2007 and 2006. Plant availability represents the percentage of time in a year that the plant is available to generate power whether actually running or not. Western Power's plant availability was affected negatively throughout 2008 and in late 2007 by an outage at the Cancarb power plant. Eastern Power achieved plant availability of 78 per cent in 2008, 18 per cent lower than 2007 as a result of outages experienced on Units 10 and 30 at Ravenswood throughout fourth quarter 2008 and a longer than expected outage at OSP in late 2008. Additionally, Bécancour, which had an availability of 97 per cent in 2007, is not included in Eastern Power's 2008 availability measurement as a result of a temporary suspension of power generation from the plant throughout 2008.

Weighted Average Plant Availability
Year ended December 31

	2008	2007	2006
Western Power	**87%**	90%	88%
Eastern Power	**78%**	96%	95%
Bruce Power	**86%**	86%	88%
All plants, excluding Bruce Power	**79%**	93%	93%
All plants	**83%**	91%	91%

Natural Gas Storage

TransCanada owns or has rights to 120 Bcf of natural gas storage capacity in Alberta, including a 60 per cent ownership interest in CrossAlta, an independently operated storage facility. TransCanada also has contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015.

Natural Gas Storage Capacity

	Working Gas Storage Capacity (Bcf)	Maximum Injection/ Withdrawal Capacity (mmcf/d)
Edson	50	725
CrossAlta[1]	32	288
Third-party storage	38	630
	120	1,643

(1) Represents TransCanada's 60 per cent ownership interest in CrossAlta, a 54 Bcf, 480 mmcf/d facility.

TransCanada believes the market fundamentals for natural gas storage remain unchanged. The Company's gas storage capability helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to Alberta and the rest of North America. The increasing seasonal imbalance in North American natural gas supply and demand has increased natural gas price volatility and the demand for storage services. Alberta-based storage will continue to serve market needs and could play an important role should additional gas supplies be connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in TransCanada's Pipelines segment.

TransCanada manages the exposure of its non-regulated natural gas storage assets to seasonal natural gas price spreads by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales.

TransCanada offers a broad range of injection and withdrawal storage alternatives tailored to customer needs in short-term to multi-year contracts. Market volatility frequently creates arbitrage opportunities and TransCanada's storage operations offer solutions to capture value from these short-term price movements. Earnings from third-party storage capacity contracts are recognized over the term of the contract. At December 31, 2008, TransCanada had contracted approximately 70 per cent of the total 120 Bcf of working gas storage capacity in 2009 and 57 per cent of storage capacity in 2010.

Proprietary natural gas storage transactions are comprised of a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, TransCanada locks in future positive margins, thereby effectively eliminating its exposure to natural gas seasonal price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair values based on the forward market prices for the contracted month of delivery. Changes in the fair value of these contracts are recorded in Revenues. Effective April 2007, TransCanada adopted an accounting policy to record proprietary natural gas inventory held in storage at its fair value using the one-month forward price for natural gas. Changes in the fair value of inventory are recorded in Revenues. Changes in the fair value of proprietary natural gas inventory in storage and natural gas forward purchase and sales contracts are excluded in determining comparable earnings as they are not representative of amounts that will be realized on settlement.

Natural Gas Storage operating income was $135 million in 2008, a decrease of $11 million compared to 2007. The decrease was primarily due to lower average storage values realized by CrossAlta, partially offset by higher earnings from the sale of proprietary natural gas at Edson in 2008. There were no net unrealized gains or losses in 2008 from changes in the fair value of proprietary natural gas forward purchase and sales contracts compared to net unrealized gains of $10 million in 2007.

Natural Gas Storage operating income was $146 million in 2007, an increase of $53 million compared to 2006. The increase was primarily due to income earned from the first full year of operations from the Edson facility.

ENERGY – OPPORTUNITIES AND DEVELOPMENTS

Ravenswood In August 2008, TransCanada acquired the multiple-unit Ravenswood generating facility located in Queens, New York, which employs dual-fuel capable steam turbine, combined-cycle and combustion turbine technology. During 2008, Ravenswood operated under a tolling arrangement that existed at the date of acquisition and expired on December 31, 2008. Under the tolling arrangement, all energy generated from the facility was provided to Hess Corporation for a fixed operating fee. In January 2009, Ravenswood commenced earning revenues from the sale of energy generated from the facility into the New York market. TransCanada's marketing operation located in Westborough, Massachusetts manages the marketing of output from Ravenswood.

The integration into TransCanada's operations of the Ravenswood generating station, acquired in August 2008, is now complete. Shortly after closing the acquisition, TransCanada experienced a forced outage event affecting one of the larger multiple generating units. The unit is currently undergoing repair and it is expected that the event will be insured both for physical damage and business interruption. Other refurbishment work is being undertaken at the station while the repair work is being completed and as a result, unit availability is expected to improve in the future.

Bruce Power Under a long-term agreement reached in 2005 between Bruce Power and the OPA, Bruce A has committed to refurbish and restart the currently idle Units 1 and 2, extend the operating life of Unit 3 with a full refurbishment and replace the steam generators on Unit 4. Bruce Power and the OPA amended the Bruce A refurbishment agreement in 2007 to allow for a full refurbishment of Unit 4, which will extend the expected operating life of the unit. Under the 2007 amendment, the OPA had the option to elect, prior to April 1, 2008, to proceed with a three-unit refurbishment and restart program instead of the revised four-unit program. The OPA chose to not exercise this option and instead elected to proceed with the four-unit refurbishment and restart program.

In fourth quarter 2008, Bruce Power completed a review of the operating life estimates for Units 3 and 4. Unit 3 is now expected to remain in commercial service until 2011, which provides the benefit of nearly two additional years of power generation before the unit commences an expected 36 month refurbishment. After the refurbishment, the operating life of Unit 3 is expected to be extended to 2038 from 2037. In addition, Unit 4 is now expected to remain in commercial service until 2016, providing nearly seven years of generation before the unit commences a similar refurbishment period, after which, the estimated operating life of Unit 4 is expected to be extended to 2042 from 2036.

The capital cost for the refurbishment and restart of Bruce A Units 1 and 2 is expected to be approximately $3.4 billion, based on a comprehensive review in January 2008 of the estimated costs to complete the project, which is an increase from the original cost estimate of $2.75 billion. TransCanada's share is expected to be approximately $1.7 billion, compared to an original estimate of $1.4 billion. The project cost increases are subject to the capital cost risk- and reward-sharing mechanism under TransCanada's agreement with the OPA. Bruce A Units 1 and 2 are expected to produce an additional 1,500 MW of power when completed in 2010.

As at December 31, 2008, Bruce A had incurred $2.6 billion in costs with respect to the refurbishment and restart of Units 1 and 2 and approximately $200 million for the refurbishment of Units 3 and 4.

Portlands Energy Construction continued in 2008 on Portlands Energy. The facility was operational in single-cycle mode in the summer of 2008 and is expected to be fully commissioned in its combined-cycle mode in first quarter 2009. Portlands Energy will provide power under a 20-year Accelerated Clean Energy Supply contract with the OPA. The expected capital cost is $730 million, of which TransCanada's portion is 50 per cent.

Coolidge In May 2008, the Phoenix, Arizona-based utility, Salt River Project, signed a 20-year power purchase contract to secure 100 per cent of the output from the simple-cycle natural gas-fired peaking power facility currently under development. In December 2008, the Arizona Corporation Commission granted a Certificate of Environmental Compatibility approving construction of the facility. Construction is expected to begin in the summer of 2009 and the facility is expected to be commissioned in 2011.

Halton Hills Construction of Halton Hills continued in 2008. The project includes the construction and operation of a natural gas-fired power plant near the town of Halton Hills, Ontario. TransCanada expects to invest approximately $670 million in the project, which is anticipated to be in service in third quarter 2010. Power from the facility will be sold to the OPA under a 20-year Clean Energy Supply contract.

Cartier Wind The Carleton wind farm commenced commercial operation in November 2008, providing up to 109 MW of power to the Hydro-Québec grid. Carleton is the third phase of the six-phase, multi-year Cartier Wind project, located in the Gaspé region of Québec. The first two phases, Baie-des-Sables and Anse-á-Valleau, went into service in November of 2006 and 2007, respectively, generating up to 110 MW and 101 MW of power, respectively. The remaining phases of Cartier Wind are expected to be constructed through 2012, subject to the necessary approvals. Capacity is expected to total 740 MW when all six phases are complete. TransCanada has a 62 per cent ownership interest in these wind farms.

Kibby Wind In July 2008, the State of Maine's Land Use Regulation Commission approved the final development plan submitted by TransCanada to build, own and operate a wind farm, located in the Kibby and Skinner townships in Maine. Construction of the facilities at a cost of approximately US$320 million began in July 2008 and commissioning of the first phase is expected to begin in fourth quarter 2009.

Bécancour TransCanada entered into an agreement with Hydro-Québec in November 2007 to temporarily suspend all electricity generation from the Bécancour power plant during 2008. In 2008, the agreement was extended through to December 2009. In 2009, TransCanada will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Power Transmission Line Projects TransCanada is pursuing proposals to build, own and operate power transmission lines, including the Zephyr and Chinook transmission line projects. The projects are each proposed 500 kilovolt (kV) high voltage direct current (HVDC) transmission lines originating in Wyoming and Montana, respectively, and terminating in Nevada. If constructed, each project would cost approximately US$3 billion and be capable of delivering 3,000 MW of power. In December 2008, TransCanada filed applications for both projects requesting approval from the FERC to charge negotiated rates and to proceed with an open season in the spring of 2009, with 50 per cent of the capacity of each line already pre-subscribed for a period of 25 years. In February 2009, the FERC approved both applications. Pending successful completion of the open seasons, regulatory work could commence later in 2009, followed by construction commencing in 2012 and a potential in-service date of late 2014.

TransCanada is pursuing a proposal to build NorthernLights, a 500 kV HVDC electric transmission line running from central Alberta to a terminal in southern Alberta and interconnecting with the Pacific Northwest. NorthernLights is expected to cost approximately $2 billion and provide up to 3,000 MW of power.

Broadwater LNG In March 2008, the FERC authorized the construction and operation of Broadwater, subject to conditions. In April 2008, the New York Department of State determined that construction and operation of the project would not be consistent with the State's coastal zone policies. As a result of this unfavourable decision, TransCanada wrote down $27 million after tax ($41 million pre-tax) of costs for Broadwater that had been capitalized to March 31, 2008. TransCanada has appealed the determination of the New York Department of State to the U.S. Department of Commerce and a decision is expected in early 2009.

ENERGY – BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices

TransCanada operates in competitive power and natural gas markets in North America. Volatility in power and natural gas prices is caused by market forces such as fluctuating supply and demand, which are greatly affected by weather events. Energy's earnings from the sale of uncontracted volumes are subject to price volatility. Although Energy commits a significant portion of its supply to medium- to long-term sales contracts, it retains an amount of unsold supply in order to provide flexibility in managing the Company's portfolio of wholly owned assets.

Uncontracted Volumes

Energy has uncontracted power sales volumes in Western Power and Eastern Power and through its investment in Bruce Power. In addition, with the acquisition of Ravenswood, at December 31, 2008, Eastern Power significantly increased its level of uncontracted sales volumes, which are subject to price volatility. Sale of uncontracted power volumes into the spot market is subject to market price volatility, which directly impacts earnings. Bruce B has a significant amount of uncontracted volumes subject to a floor price mechanism that are sold into the wholesale power spot market under contract price terms with the OPA, while 100 per cent of the Bruce A output is sold into the Ontario wholesale power spot market under fixed contract price terms with the OPA. The natural gas storage business is subject to fluctuating natural gas seasonal spreads generally determined by the differential in natural gas prices in the traditional summer injection and winter withdrawal seasons. As a result, the Company hedges capacity with a portfolio of contractual commitments containing varying terms.

Liquidity Risk

A decrease in the number and credit quality of counterparties with which to transact may increase the Company's exposure to spot prices by reducing its ability to lock in forward sale prices at acceptable contract terms.

Plant Availability

Maintaining plant availability is essential to the continued success of the Energy business. Plant operating risk is mitigated through a commitment to TransCanada's operational excellence strategy, which is to provide low-cost, reliable operating performance at each of the Company's facilities. Unexpected plant outages and the duration of outages could result in lower plant output and sales revenue, reduced margins and increased maintenance costs. At certain times, unplanned outages may require power or natural gas purchases at market prices to ensure TransCanada meets its contractual obligations.

Weather

Extreme temperature and weather events in North America and the Gulf of Mexico often create price volatility and demand for power and natural gas. These same events may also restrict the availability of power and natural gas. Seasonal changes in temperature can also affect the efficiency and output capability of natural gas-fired power plants. Variability in wind speeds may impact the earnings of the Cartier Wind assets.

Hydrology

TransCanada's power operations are subject to hydrology risk arising from the ownership of hydroelectric power generation facilities in the northeastern U.S. Weather changes, weather events, local river management and potential dam failures at these plants or upstream facilities pose potential risks to the Company.

Execution and Capital Cost

Energy's new construction programs in Ontario, Québec, Maine and Arizona, including its investment in Bruce Power, are subject to execution and capital cost risks. At Bruce Power, Bruce A's four unit refurbishment and restart project is also subject to a capital cost risk- and reward-sharing mechanism with the OPA.

Asset Commissioning

Although all of TransCanada's newly constructed assets go through rigorous acceptance testing prior to being placed in service, there is a risk that these assets may have lower than expected availability or performance, especially in their first year of operations.

Regulation of Power Markets

TransCanada operates in both regulated and deregulated power markets. As electricity markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation that negatively affects the price for capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedule and cost. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead discussions around these topics.

Refer to the "Risk Management and Financial Instruments" section of this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY – OUTLOOK

TransCanada assumes that its operations in 2009 will be materially consistent with those in 2008 and includes the positive impact of a full year of earnings from Ravenswood, incremental earnings from Portlands Energy, which is expected to be commissioned in first quarter 2009, and a decrease in planned outages at Bruce Power. These positive impacts are expected to be partially offset by a return to more normal hydrology levels at TC Hydro from the record levels experienced in 2008. In addition, the current economic climate is negatively affecting demand, liquidity and prices in commodity markets in which TransCanada operates.

Although TransCanada has sold forward significant output from its power plants and Alberta PPAs, as well as capacity from its natural gas storage facilities, operating income in 2009 can be affected by changes in the spot market price of power, market heat rates, hydrology, forward capacity payments, natural gas storage spreads and unplanned outages. Operating income from Energy's U.S. operations is affected by changes in the U.S./Canadian dollar exchange rates.

Other factors such as plant availability, regulatory changes, weather, currency movements, and overall stability of the energy industry can also affect 2009 operating income. Refer to the "Energy – Business Risks" section of this MD&A for a complete discussion of these factors.

Following the expiry of the Ravenswood tolling arrangement with Hess Corporation on December 31, 2008, TransCanada will manage the ongoing marketing of the Ravenswood plant output in the same manner as it does with other generation assets in the U.S. Northeast. Dependent on market liquidity and other factors, a significant portion of the electricity generated by the Ravenswood facility in 2009 and beyond may be sold at spot prices. As noted in the "Energy – Business Risk" section of this MD&A, spot prices for electricity are subject to change depending on underlying energy commodity prices, available supply, demand and other factors.

Capital Expenditures

Energy's total capital expenditures in 2008 were $4.3 billion, including the acquisition of Ravenswood for $3.1 billion. Energy's overall capital spending in 2009 is expected to be approximately $1.4 billion, including cash calls for the Bruce A refurbishment and restart project and continued construction at Coolidge, Cartier Wind, Kibby Wind and Halton Hills.