



C a n a d i a n

Natural Gas Market Report[®]

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Highlights

It is probably impossible to account for the number of papers, talk-shows and debates dedicated to Enron. The fall of the Houston giant raised passion and controversy. The tremendous effect generated by the fallout of the number one US energy trader was felt as far as Tanzania, India and Pakistan, the total global exposure to Enron being estimated to as much as \$1 trillion. Enron's collapse turned the spot light on energy trading and marketing, rating agencies and accounting practices and enriched the business vocabulary with new words like "enronitis" (referring to the impact of Enron's bankruptcy on different aspects of life). See p. 2

Total consumption of natural gas in the AEO2006 reference case is projected to increase from 22.4 trillion cubic feet in 2004 to 27.0 trillion cubic feet in 2025, 3.7 trillion cubic feet lower than projected in the AEO2005 reference case, mostly as a result of higher natural gas prices. After peaking at 27.0 trillion cubic feet in 2024, natural gas consumption is projected to fall slightly by 2030, as higher natural gas prices result in a larger market share for coal in the electric power sector in the later years of the projection. The projected growth in natural gas demand in AEO2006 results primarily from increased use of natural gas for electricity generation and industrial applications, which together account for 62 percent of the projected demand growth from 2004 to 2025. In addition, demand for natural gas in the residential and commercial sectors is projected to grow by 1.5 trillion cubic feet in total from 2004 to 2025. than the AEO2005 projection). See p. 12

A combination of political risk and new fuel specifications should keep benchmark crude oil futures above \$60 during 2006, according to a forecast released by the Cambridge Energy Research Associates (CERA) in February. Presenting the 2006 oil outlook at the CERA's conference, James Buckhard, CERA senior director and head of global oil market analysis, said despite a host of factors that should be pushing prices down these "specification changes along with geopolitical risk are likely to keep prices above \$60 at about \$62 on an annual average basis", Dow Jones informs. See p. 12

Williams' Northwest Pipeline, Pacific Gas and Electric Company and Fort Chicago Energy Partners L.P. have agreed to jointly pursue the development of a major new gas transmission pipeline that would increase natural gas supplies for the West Coast of the United States. The three participants will hold equal interests in the pipeline project. The proposed Pacific Connector Gas Pipeline, a 250-mile natural gas transmission line, together with the proposed Jordan Cove liquefied natural gas terminal in Coos Bay, Ore., being developed by Fort Chicago, are designed to bring new diverse worldwide natural gas supply sources to West Coast markets. See p. 13

Natural Gas News: TransCanada Files for Expansion Certificate for North Baja Pipeline; US Tribes To Give Land Testimony in Right-of-Way Hearing; AGA Executive Commends Senate Energy Committee for Continued Focus on Natural Gas Supply; Proposed Federal 5-Year Plan for Offshore Energy Moves Toward Greater Natural Gas Supply But Needs Work According to AGA; California Public Utilities Commission Moves To Cut Greenhouse Gas Emissions; FERC: Warm Weather Kept Prices Low but Increased Generation May Increase Gas Prices; Keyspan In Talks on Possible Sale. See pp. 14-16

Natural Gas Market Feature Article:

Enron - The Good, the Bad and the Ugly

By Ion Nichifor

It is probably impossible to account for the number of papers, talk-shows and debates dedicated to Enron. The fall of the Houston giant raised passion and controversy. The tremendous effect generated by the fallout of the number one US energy trader was felt as far as Tanzania, India and Pakistan, the total global exposure to Enron being estimated to as much as \$1 trillion. Enron's collapse turned the spot light on energy trading and marketing, rating agencies and accounting practices and enriched the business vocabulary with new words like "enronitis" (referring to the impact of Enron's bankruptcy on different aspects of life).

Enron's breakdown was a blow beyond financial implications, as the energy trader represented the "American dream", an extraordinary and quick ascension to greatness and power. The Texas-based firm was feared and envied, loved and hated, but unanimously considered a model for the future. The New York Times named Enron a "model for the new American workplace" in spite of its ongoing investigation into the company's political contributions. In just over 15 years, Enron turned itself from a regulated natural gas company into one of the world's largest energy traders. Its online trading platform, EnronOnline has been the most innovative and successful energy trading system to this day.

Its fall, however, was even faster than its rise. Within weeks, from November to December 2001, the once mighty power trader turned into the third largest bankruptcy in the history of US (after Texaco and WorldCom), wiping out about \$850 million in pension savings, 5500 jobs and leaving behind at least \$31 billion of debt.

This article focuses on three aspects. "The good" represents Enron's accomplishments in the energy-trading sector and the development of the EnronOnline trading platform. "The bad" shows how markets inexplicably chose to ignore Enron's lack of financial transparency. The secrecy that surrounded Enron allowed the company to hide losses and pose as a healthy, functional company long after it became insolvent. "The ugly" represents the inflated ark-to-market and volume trading techniques Enron used to consolidate its market position, which, ultimately, led to Enron's demise.

Brief History:

Enron was formed in July 1985 by the merger of Houston Natural Gas and InterNorth of Omaha, Nebraska. Initially named Enteron, after being told that the name suggested intestines, the company changed its name to Enron. Although it started as a natural gas pipeline company, Enron rapidly evolved from delivering energy to brokering energy futures as energy markets were deregulated. The company began marketing electricity in 1994 and entered the European energy market in 1995.

Enron grew rapidly, containing three businesses - energy, wholesale and global services. In 1999, Enron launched a plan to

buy and sell access to high-speed Internet bandwidth, and it launched EnronOnline, a Web-based commodity-trading site. It had stakes in nearly 30,000 miles of gas pipelines, owned or had access to a 15,000-mile fiber optic network and had a stake in electricity generating operations around the world. The company had more than 21,000 employees around the world and its revenues exceeded \$100 billion in 2000. Enron was not merely a trader of commodities or products such as metals or air-emissions credits, but also the market maker in energy trading as well as the trading of bandwidth and weather derivatives. Enron developed its own on-line credit evaluation model (Enron Cost of Credit), which, not surprisingly, made the company look creditworthy as far as October 2001.

As recently as August 2001, the company has won a series of awards, including Fortune's "America's Most Innovative Company" award for an unprecedented six years between 1996 and 2001 and the Financial Times' "Energy Company of the Year" award and "Boldest Successful Investment Decision" in 2000.

However, in July 2001, Enron warned its investors it would post a large loss in its quarterly statement. The company blamed losses on the California energy crisis and poor results from its foreign investments. Then, in August 2001, Jeffrey K. Skilling, president and chief executive officer of Enron surprised the financial world by resigning after less than a year in charge, invoking personal reasons. In October 2001, Enron said it would reduce shareholder value by \$1.2 billion. The company blamed the losses on its broadband division, international subsidiaries, and its partnerships. Soon after, the Texas-based company fired Andrew Fastow, the chief financial officer, for allegedly arranging dubious partnerships. Enron disclosed that the SEC (the Security Exchange Commission) had requested the Texas energy trader to provide information "regarding certain related party transactions" in the start of an informal inquiry.

Enron revealed in early November that it had overstated its profits by almost 16 percent, or \$600 million, since 1997. Arthur Andersen, Enron's auditor, alerted shareholders that they should not trust any financial reports issued before June 30, 2001. Amid the controversy, Enron's stock plunged.

However, for a few weeks in November 2001, there was faint hope for Enron, when Dynegy announced it was close to agreeing to a rescue bid of about \$8 billion for Enron, after the former number one trader had barely escaped having its credit ratings cut to junk status. Enron also managed to secure a \$1 billion credit line from JP Morgan Chase and Salomon Smith Barney. However, by the end of November, almost simultaneously, Enron's credit ratings were cut below investment grade and Dynegy pulled out from the merger.

On December 2, 2001, Enron announced it had filed for Chapter 11 bankruptcy. The rest is already history. Enron irrupted

like an infection revealing an enormous debt, thousands of financial schemes and wiped out pension funds and savings. As the investigations into the Enron's business developed misstatements and errors of judgment were revealed on an almost weekly basis. Dozen of lawsuits have been started against Enron since December 2001, ranging from stockholders' action suits to financial fraud and criminal allegations. Most of these lawsuits are still unfolding and conclusions or verdicts are far from being crystallized.

The Good:

According to company data, by September of 2001, EnronOnline was processing about 4,000 transactions per day worldwide, with an average deal size of about \$500,000. At an annualized rate, the nominal value of online transaction activity conducted through EnronOnline was approximately \$510 billion (General Center for Internet Services). Forrester Research estimated that the trade of physical energy products was about \$1.4 trillion in 2001, while financial products within the energy industry was \$3.6 trillion in North America alone. EnronOnline traded in both physical and financial energy products, with an emphasis on financial products.

Enron convinced several companies to transform their businesses by relying less upon phone transactions and more upon internet-based trade. A very important and unique feature of the Enron Online system was that the company acted more than a mere intermediary between two market players. Most online energy trading sites work by pairing up buyers and sellers; Enron, however, was a party, either as a buyer or seller, to every trade on Enron Online (BBC News Online).

As Forbes' Tony Mack described in a 1993 article, Enron's trading model placed Enron in the heart of every transaction, even before EnronOnline was created: "Enron has two five-year contracts - one to sell a certain amount of gas to a utility, another to buy the same amount of gas from a producer. Netting one against the other yields a gross profit to Enron of \$2.2 million. Enron then deducts shipping costs and reserves for unforeseen costs. That leaves profits of \$930,000 over the life of the contracts, or \$729,000 at present value after discounting at 8.7%."

After EnronOnline kicked off in 1999, Enron continued its ambitious role to serve as a counterparty to each online transaction. This eventually led to a highly-leveraged financial position which, in turn, pushed Enron into bankruptcy. As Business Week noted, the company smoothed out its profit stream by suppressing both the spikes and the dips in trading. "If they had played it straight, they still would have had decent results," said energy trader Art Gelber, head of Gelber & Associates in Houston. "But they would have lost their image of being so good that nothing could go wrong."

Enron's collapse created a huge vacuum in the energy-trading sector. Although other online trading exchanges have seen a steady increase in their transaction activity, they failed to replace EnronOnline in volume and geographic coverage. Most of these energy traders such as Intercontinental Exchange or TradeSpark primarily serve as online marketplaces, helping buyers and sellers find each other and transact, but they leave credit and settlement arrangements to be made between the individual

parties to each transaction. The Intercontinental Exchange does not act as a counterparty to transactions that are conducted through its system.

Although Enron Online has been purchased by UBS Warburg in 2002, the revival of the once mighty energy trader is not foreseen in the near future. UBS, still faces challenges in its bid to return Enron Online to glory, including persuading energy traders to bring their business back to the online exchange.

In Canada, the collapse of Enron generated major market shifts. Mirant, through its subsidiary Canada Energy Marketing, Ltd., jumped in with its purchase of TransCanada Pipelines Limited's physical and financial trading business and related gas transportation and storage contracts. Duke Energy Corp. has also entered the Canadian gas marketing sector through its midstream transportation business and by acquiring Westcoast Energy and its trading arm, Engage Energy, in the first quarter of 2002 (Nickle's Market View).

As Rod Pocza, president of Mirant Canada declared in 2002, the bankruptcy of Enron, which was marketing about 26.1 bcf per day in 2001, represented a great opportunity for companies like Mirant or Duke to fill up the void: "Over time, the market works. Enron brought a lot of creative, innovative solutions to the market, but the liquidity issue on the gas side will be absorbed by the major players. Clearly they were the largest ... (and) that does spell opportunity for people to work with their customers and to pick up a lot of new business.

Nevertheless, neither Mirant, Duke nor other players have been able to fully replace Enron as the energy trading sector does not yet enjoy the same level of liquidity and accessibility as during Enron's reign. The Canadian Natural Gas Market Report shows the effects of Enron's collapse: "Since the demise of EnronOnline, there is no easily accessible price discovery mechanism in B.C., although the Intercontinental Exchange may become such a mechanism. In the past year (2002), the number of parties trading gas has declined. Certain end-users report that they have been unable to buy gas directly from producers and some other shippers on the Westcoast system. They also report a limited amount of transportation capacity on the secondary market."

The Bad:

This is a story, allegedly not entirely untrue, that circulated in Communist Romania before 1990. A small farm in one of the remote areas of the country had to report the semi-annual agricultural results to the Local Committee. The report is short and concise: "Unit no. 2 gladly announces it has completed work at half of its 10 hectares of wheat. We will continue the process until final completion. Glory to the Party." The Local Committee reads the report and decides that it should inflate the results, as it was commonly done in many communist countries. As a result, the Local Committee changes the 10 hectares to 100 hectares and forwards the report to the Regional Committee. The Regional Committee forwards the report, after making its own upward adjustment to the numbers, to the Central Committee, which submits the report to the Ministry of Agriculture, after "recalibrating" the results again. A reply comes from the Ministry the very next day: "To all levels: stop any activity at Unit no. 2."

You have crossed the national borders.”

Unfortunately, the Wall Street and the mass-media were not as perspicacious as the Communist bureaucrats. Although many agree now that the hallucinating results reported by Enron between 1997-2001 should have prompted more caution and raised a few question marks, at that time, they were regarded normal and “within expectations”.

Equity analysts and credit rating agencies recognized that they were not aware of Enron's financials, but they were all recommending the stock without hesitation. In response to the question “How is Enron generating its money?” most analysts were simply shrugging: “If you figure it out, let me know,” (Todd Shipman, S&P credit analyst) or “Do you have a year?” (Ralph Pellecchia, Fitch credit analyst).

Enron financials could be easily described as a “black box”. Analysts believed that the 2000-2001 volatility in gas and power markets was enhancing Enron's profits, but they admitted that “the ability to develop a somewhat predictable model of this business for the future is mostly an exercise in futility” (Robert Winters, Bear Stearns analyst).

While riding the wave of a superheated economy in which experts were talking about eternal economic growth and the death of the economic cycle, it was easy for Enron to disguise its problems and pose as the “model of the future”. Andrew Fastow, while pointing out that Enron had 1,217 trading “books” for different commodities, explained: “We don't want anyone to know what's on those books. We don't want to tell anyone where we're making money.” The market did not seem to care too much about Enron's secrecy as long as the Texas giant was producing the results. Enron's stock was trading at the end of 2000 at approximately \$90/share and at roughly 55 times trailing earnings (more than 22 times the multiple of Duke Energy and more than twice that of the S&P 500 at that time).

Enron was even graciously downplaying the risk of its trading operations. The company was explaining to anybody interested to listen that its core business was delivering a physical commodity and, unlike a trading firm, volatility had no effect on its profits—other than to increase the number of customers, who would turn to the company during unstable times. Jeff Skilling described Enron's wholesale business as “very simple to model,” and Andrew Fastow pointed out that the growth in Enron's profitability was tracking the growth in its volumes almost perfectly.

However, Enron knew that its reign would last as long as they were producing results as Enron used its own stock to backstop hedging energy contracts and other commitments. To fulfill expectations, Enron founded Special Purpose Entities (SPEs) designed to take debt off-balance sheet, and hide losses and inflated mark-to-market results (William Powers - Enron Investigation Report).

Besides the market optimists who were blinded by Enron's golden aura of profitability and success, there was another segment of Enron supporters: financial institutions, business partners, portfolio managers and market analysts who were deeply interlinked with Enron. Citibank, Bank of NY and JP Morgan alone had a combined exposure to Enron of \$7.5 billion as of December 2001. It is reasonable to believe that most financial institutions that lent money to Enron, held Enron's stock

or were involved in diverse partnerships with the Texas-based energy trader, were induced by large fees and had all the incentives to support Enron's myth and issue positive recommendations, in spite of signs that the energy trader was “wallowing in the mires”.

The Ugly:

“Mark-to-market (MTM) means that financial assets, such as marketable securities, derivatives and financial contracts, are reported on a company's balance sheet at their current market value at a specific point in time, although the actual realization of cash may not happen for years in the future.” (Bloomberg)

Due to MTM, Enron was able to book its energy trading contracts at the full contract price. The company acted like a broker taking credit for the full sales price, instead of the commission that they earned on selling the stock. As an example, if a customer sells 1,000 shares of stock through a broker for \$45,000, the broker would book the commission on the sale or the spread between the bid price and the ask price, (for example \$500). Enron, however, would book a gas contract for \$45,000.

Enron produced inflated revenues, but relatively small profits, by buying and selling the same commodities several times. “A lot of it is from buying and selling the same [gas or electricity] multiple times. They might resell to one customer the same electricity they sold to another,” says Charles Fischman, an analyst at A.G. Edwards.

According to Douglas Carmichael, an accounting professor at Baruch, Enron was able to book the full value of the contracts because FASB (Financial Accounting Standards Board) could not decide how energy contracts should be accounted for. Because the FASB allowed each company to decide over how to account their energy contracts, Enron opted for the highest possible value. Although not illegal, the practice was misleading and hid the real volume of the revenues.

In May 2002, an investigation into the Enron's memos revealed different practices used by the Texas-based energy trader and its partners during 2000-2001 to manipulate energy prices on the California market or artificially increase revenues. The finding led to FERC investigating the activity of all energy traders who participated on California's markets during 2000-2001. Important players like Williams, Dynegy, Reliant, Duke, CMS admitted being involved in some of these “scam” trades and their share price plummeted. Among these practices, some of the most mentioned were: “wash-trading” or “round-tripping”, “” and “ricochet”.

Wash-trading occurs when two companies are buying and selling electricity/gas to each other at the same price, in essence canceling out the transaction but showing a higher volume of trade and revenue for each company. The transactions may create the impression of an active market and boost companies' trading volume, but in fact show no gains or losses on balance sheets. Many companies like Enron, Dynegy and Williams used wash-trades to consolidate their position as leading traders and even set benchmark prices for MTM purposes. Volume of trading was important for energy traders as many business partners used market position of counterparties as criteria of reliability and creditworthiness. Although wash-trades had no impact on

earnings, they offered the possibility of reporting large volumes of sales and, therefore, a "leading" market position. Enron abused of wash-trades to consolidate its position as number one energy trader in the US.

Enron also submitted artificial schedules in order to receive inter-zonal congestion payments. Another technique called "ricochet" technique involved Enron buying energy from Cal PX and exporting to another entity which charged a small fee. Then the energy was returned to Enron who resold it to Cal ISO in the real-time market.

Enron used to report on the company's financial statement the sale of an asset, without mentioning the hidden guarantee that the entity buying the asset would receive a certain rate of return. Moreover, the hidden guarantees would not show on the books as a liability. The books would record only the sales as funds flow. Enron also inflated the value of the assets for sale. The former number 1 trader would repurchase an asset for \$10 million and shortly it would appear on Enron's books as an asset worth \$15 million.

The purpose of a hedging transaction is to contract an outside party that is prepared to take over the economic risk of a transaction for a price. However, some of the cases, Enron hedged the economic risk with itself. Enron created a hedging position by transferring its own stock to the SPEs at a discount to the market price. As long as Enron's stock remained unchanged or gained value, the SPE could use Enron's "embedded" value to counteract the decline in its own value. Nevertheless, when the value of Enron's investments started to fall in 2000-2001, the SPEs' hedging obligations to Enron grew accordingly. If Enron's stock would have gone up, too, the SPE might have been able to meet their obligation to Enron. But as the value of Enron's share dropped, the SPEs could not fulfill their hedging commitments.

When Enron had to terminate its SPEs it incurred losses of \$544 million. Enron also had to reduce shareholder equity by \$1.2 billion due to "correction of accounting errors" related to Enron's prior issuance of Enron common stock to SPEs. The "hedging transactions" with its own SPEs enabled Enron to hide more than \$1 billion in merchant investment losses between 2000 and 2001 (William Powers - Enron Investigation Report).

Conclusion:

The Enron disaster triggered an increasing lack of investors' confidence in the ability of markets and regulatory bodies to spot and weed out fraud. The bankruptcy of the former number one energy trader, combined with the September 11 attacks and a lagging economy, were the main cause behind the stock market plunge in 2002. The public perception was that "too many corporate executives have committed breaches of trust by 'cooking the books', hiding the truth and enriching themselves with stock-option profits while shareholders suffered great losses."(BusinessWeek Online)

Enron's bankruptcy brought changes to accounting standards and market transparency rules. It also brought the energy-trading sector under scrutiny. If prior to 2001 energy companies were boasting about profits done through their energy trading arms, after Enron's failure most market players tried to distance themselves from the disgraced Enron business model. Merchant energy companies shifted towards a more asset-based structure and reduced their trading activity.

Enron has become the personification of corporate corruption and mismanagement, which overshadows Enron's accomplishments and role in the energy markets. In spite of, but also because of its aggressive approach to trading, Enron became the largest energy trader in North-America, creating and managing a highly liquid market for both energy and energy related products. Enron was an avid promoter and user of derivative contracts. After its collapse, liquidity in many OTC energy products dried up. Although Enron's practices were plagued by unethical behaviour such as wash-trading, volume trading or misleading MTM, the company offered a solution for a truly fluid and comprehensive North-American energy market.

continued on page 11...

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**Alberta spot gas price at border
& Toronto city-gate \$/GJ**

CS/GJ	Alberta Spot Gas		Alberta 1-Year Gas	
	Border	Toronto	Border	Toronto
D1	5.44	6.64	5.25	6.45
D15	7.38	8.58	5.33	6.54
J5/04	6.65	7.87	5.48	6.71
J19	6.82	8.05	5.88	7.11
F2	6.64	7.86	5.88	7.10
F16	6.14	7.36	5.92	7.14
M1	6.02	7.24	5.93	7.16
M15	6.07	7.29	6.19	7.41
A5	6.07	7.29	6.25	7.47
A19	6.53	7.76	6.54	7.76
M3	6.53	7.76	6.50	7.72
M17	7.43	8.65	7.21	8.44
J1	7.22	8.44	7.40	8.63
J14	6.64	7.86	7.09	8.32
J5	6.76	7.99	7.21	8.44
J12	6.75	7.97	7.07	8.30
A5	6.70	7.92	7.23	8.45
A16	6.49	7.71	7.15	8.37
S1	5.95	7.18	7.07	8.30
S20	5.37	6.59	6.79	8.02
O5	5.50	6.72	6.88	8.10
O18	7.19	8.42	7.74	8.96
N1	7.74	8.96	7.95	9.17
N15	7.48	8.70	6.96	8.19
D1	7.33	8.55	7.01	8.23
D13	6.85	8.08	6.64	7.86
J3/05	6.75	7.97	6.69	7.91
J17	6.23	7.45	6.51	7.73
F1	6.32	7.54	6.58	7.80
F14	6.36	7.58	6.82	8.04
M1	6.41	7.63	6.89	8.12
M14	6.94	8.16	7.35	8.57
A4	7.22	8.44	7.58	8.80
A18	7.52	8.74	7.93	9.15
M2	7.41	8.63	7.98	9.20
M16	6.96	8.18	7.65	8.88
J1	6.74	7.96	7.66	8.88
J13	6.19	7.42	8.06	9.29
J4	7.14	8.36	8.18	9.40
J18	7.71	8.93	8.45	9.67
A2	7.32	8.54	8.42	9.64
A15	8.98	10.20	9.36	10.58
S6	9.20	10.43	9.50	10.72
S19	10.37	11.59	10.77	11.99
O3	11.09	12.31	11.18	12.40
O17	12.74	13.96	11.84	13.06
N1	12.23	13.45	11.74	12.97
N14	10.38	11.60	9.49	10.71
D5	10.36	11.59	9.71	10.93
D19	13.25	14.47	10.17	11.39
J3/06	11.63	12.62	10.26	11.25
J16	8.77	9.76	9.44	10.43
F1	8.13	9.12	9.53	10.52
F13	7.32	8.31	8.90	9.89

Domestic gas market

Daily Spot Gas Price at AECO C & Nova Inventory Transfer

Month	Volume (TJ/d)	Number of Transactions	Price (\$/GJ)			Avg. Price US\$/MMBtu	
			Low	High	Avg.*		
February 2006							
Wednesday	1	1584.9	225	7.6500	8.3450	8.1765	7.5656
Thursday	2	1697.7	217	7.1500	7.3500	7.2497	6.6904
Friday	3	517.9	68	7.2000	7.6500	7.3554	6.7655
Weekend#		1244.4	191	7.1750	7.6500	7.3339	6.7457
Saturday	4	219.0	35	7.3500	7.4900	7.4290	6.8332
Sunday	5	209.5	29	7.3850	7.6000	7.4888	6.8882
Monday	6	1389.8	199	7.2200	7.6000	7.4517	6.8619
Tuesday	7	1507.0	202	7.0900	7.3100	7.2076	6.6174
Wednesday	8	1312.8	196	6.9500	7.2700	7.1768	6.5641
Thursday	9	1414.8	182	6.7000	7.0900	6.8998	6.3559
Friday	10	492.4	73	6.7400	6.9500	6.8624	6.2729
Weekend#		823.1	121	6.7000	6.9200	6.8560	6.2671
Saturday	11	165.5	42	6.1900	6.6100	6.4610	5.9060
Sunday	12	190.6	36	6.4650	6.7000	6.5440	5.9819
1. Tot./Wtd. Avg.**	12769.4	1816	6.190	8.345	7.2939	6.7090	
1A. Arithmetic Avg.**					7.1780	6.5940	
2. Tot./Wtd. Avg.^	10701.9	1504	6.190	8.345	7.3229	6.7388	
2A. Arithmetic Avg. ^					7.1919	6.6086	

* Weighted average price. #Weighted average of NGX "W" instrument (Friday, Saturday & Sunday). ** Includes Weekend deals.

^ Excludes Weekend# deals. Note: Weekend# deals include statutory holiday Fridays and Mondays.

Source: Natural Gas Exchange. Exchange rate from Bank of Canada (noon day rate). @Denotes holiday.

Daily Spot Gas Price at Empress

Month	Volume (TJ/d)	Number of Transactions	Price (\$/GJ)			Avg. Price US\$/MMBtu
			Low	High	Avg.*	
February 2006						
Wednesday	1	7.7500	8.4750	8.2890	7.6697	
Thursday	2	7.2600	7.4750	7.3652	6.7970	
Friday	3	7.3100	7.7750	7.4724	6.8731	
Weekend#		7.2960	7.7750	7.4568	6.8587	
Saturday	4	7.4710	7.6150	7.5519	6.9462	
Sunday	5	7.5060	7.7250	7.6117	7.0012	
Monday	6	7.3410	7.7250	7.5746	6.9751	
Tuesday	7	7.2100	7.4450	7.3336	6.7330	
Wednesday	8	7.0750	7.3975	7.3019	6.6785	
Thursday	9	6.8250	7.2190	7.0271	6.4731	
Friday	10	6.8700	7.0900	6.9962	6.3952	
Weekend#		6.9500	7.2700	7.1435	6.5299	
Saturday	11	6.4400	6.9600	6.7485	6.1688	
Sunday	12	6.7150	7.0500	6.8315	6.2447	
1. Tot./Wtd. Avg.**	6.440	8.475	7.3541	6.8350		
1A. Arithmetic Avg.**			7.2627	6.6673		
2. Tot./Wtd. Avg.^	6.440	6.960	7.4501	6.8557		
2A. Arithmetic Avg. ^			7.3420	6.7463		

* Weighted average price. #Deals done on Friday for the Weekend. ** Includes Weekend# de-

^ Excludes Weekend# deals.

Note: Weekend deals include statutory holiday Fridays and Mondays. @Denotes holiday.

Source: Canadian Enerdata survey. Exchange rate from Bank of Canada (noon day rate).

Canadian Gas Utility Wacogs (\$/GJ)			
<i>Enbridge Consumers Gas* - December 2005</i>			
	With Fuel	W/O Fuel	
Western Intra-Alberta buy/sell	11.43471	10.73746	
Western buy/sell	11.59906	10.90181	
Ontario (City Gate) buy/sell	12.59658		
Western buy/sell forecast			
	February	11.64738	
	March	11.59741	
<i>Union Gas Ltd. WACOG# Oct 2005</i>			
		FT	
Western Buy/Sell Prices	Average Alberta Border price	9.0750	
	Compressor Fuel Charge	0.4270	
Ontario Buy/Sell Prices	Transportation Tolls	0.9980	
	Landed Cost	10.5000	
<i>Centra Gas Manitoba WACOG**</i>			
	Dec-05	8.6900	Nov-05 8.1238
<i>Gaz Metro WACOG**</i>			
(Without Fuel)	Feb-06	8.0800	Jan-06 10.0900
		* Updated twice a month	
		** Updated monthly	
		# Updated quarterly	

Daily Spot Gas Price at Station 2, B.C.						
Month	Volume (TJ)	Number of Transactions	Price (\$/GJ)			Avg. Price US\$/MMBtu
			Low	High	Avg.*	
February 2006						
Wednesday	1	29	7.580	7.685	7.6301	7.0600
Thursday	2	25	6.690	6.850	6.7710	6.2486
Weekend#		25	6.750	6.900	7.1206	6.5495
Saturday	4	-	-	-	-	-
Sunday	5	-	-	-	-	-
Monday	6	27	6.950	7.017	6.9876	6.4345
Tuesday	7	32	6.640	6.720	6.6789	6.1319
Wednesday	8	23	6.700	6.850	6.7722	6.1941
Thursday	9	26	6.587	6.650	6.5876	6.0683
Weekend#		31	6.400	6.560	6.5209	5.9608
Saturday	11	-	-	-	-	-
Sunday	12	-	-	-	-	-
1. Tot./Wtd. Avg.**	2390.6	218.0	6.400	7.685	6.8287	6.2740
1A. Arithmetic Avg.**					6.8836	6.3310
2. Tot./Wtd. Avg.^	1500.3	162.0	6.587	6.650	6.8644	6.3157
2A. Arithmetic Avg.^					6.9045	6.3562

* Weighted average price. #Deals done on Friday for the Weekend. ** Includes Weekend# deals. ^ Excludes Weekend# deals.
 Note: Weekend# deals include statutory holiday Fridays and Mondays. @Denotes holiday.
 Source: Canadian Enerdata survey. Exchange rate from Bank of Canada (noon day rate).

Canadian Natural Gas Derivative Prices

February 16, 2006

	Fixed Floating Swap Price C\$/GJ				NYMEX Differential US\$/MMBtu			
	AECO		Empress		AECO		Empress	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
March 2006	6.910	6.930	7.050	7.070	-0.819	-0.837	-0.691	-0.710
April 2006	7.060	7.080	7.180	7.200	-0.856	-0.875	-0.747	-0.765
Mar/06-Oct/06	7.210	7.230	7.340	7.360	-1.010	-1.028	-0.891	-0.910
Apr/06-Oct/06	7.250	7.270	7.380	7.400	-1.040	-1.058	-0.921	-0.939

Prices are for indication purposes only.

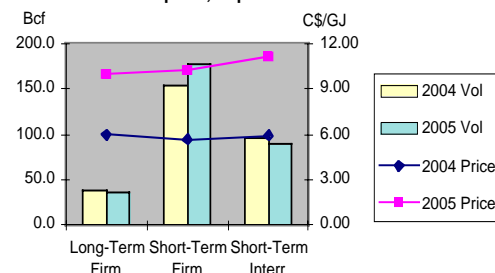
Source: Canadian Enerdata survey

Natural Gas Exports By Term, Region and Customer, September 2005

Term	Volume (Bcf)			Price* (Cdn\$/GJ)		
	2004	2005	% Chg.	2004	2005	% Chg.
Long-Term Firm	38.7	34.5	-10.9	5.95	9.99	67.9
Short-Term Firm	153.7	176.1	14.6	5.67	10.23	80.4
Short-Term Interr.	95.7	88.4	-7.6	5.94	11.16	87.9
Total	288.1	299.0	3.8	5.80	10.47	80.5
Region						
California	43.3	37.3	-14.0	5.70	9.31	63.3
Midwest	127.0	121.5	-4.3	5.79	10.71	85.0
Mountain	1.6	1.3	-16.1	5.60	12.55	124.1
Northeast	90.3	105.6	17.0	5.94	11.44	92.6
Pacific Northwest	25.9	33.4	28.6	5.50	7.80	41.8
Total	288.1	299.0	3.8	5.80	10.47	80.5
Customer						
End-User	29.5	49.7	68.2	5.62	8.76	55.9
LDC	54.5	36.0	-33.9	6.22	11.01	77.0
Marketing Co.	201.6	209.0	3.6	5.71	10.81	89.3
Pipeline	2.4	4.4	78.7	6.10	9.40	54.1
Total	288.1	299.0	3.8	5.80	10.47	80.5

* Weighted average price at the international border.

Source: National Energy Board.

Canadian Gas Exports, September 2005**Canadian Enerdata Gas Storage Survey* (Bcf)**

	This Week	Last Week	Diff.	% Chg	% Full	Maximum Same Wk Capacity			% Full Last Year
	10-Feb	3-Feb	(Bcf)			Capacity Last Year	Last Year	Last Year	
East	156.4	165.0	-8.6	-5.2%	62.33%	251.0	113.9	250.7	45.45%
West	154.5	159.5	-5.0	-3.1%	54.83%	281.8	89.0	232.4	38.30%
Total	310.9	324.5	-13.6	-4.2%	58.36%	532.8	202.9	483.0	42.01%

Source: Canadian Enerdata Ltd.

Survey does not include the storage at the Alberta HUB and Husky

*Working gas in storage including LNG, Canadian operators of storage and Canadian companies contracting storage in the U.S and Canada.

U.S. Estimated Working Gas in Storage, Week Ending February 10, 2006

	This Week	Last Week	Difference	Last Year	Difference	Difference	5- Year Avg.	Difference	Difference
	10-Feb	3-Feb	Bcf	Bcf	Bcf	(%)	Bcf	Bcf	(%)
Producing Region (1)	703	724	-21	579	124	21.4%	481	222	46.2%
Consuming Region East(2)	1249	1319	-70	992	257	25.9%	874	375	42.9%
Consuming Region West(3)	314	325	-11	250	64	25.6%	220	94	42.7%
Total U.S.	2266	2368	-102	1931	335	17.3%	1575	691	43.9%

Source: Energy Information Administration,

(1) Includes Texas, Oklahoma, Kansas, New Mexico, Louisiana, Arkansas, Mississippi.

(2) All states east of the Mississippi River except Mississippi, plus Iowa, Nebraska and Missouri.

(3) All states west of the Mississippi River except the Producing Region and Iowa, Nebraska and Missouri.

Futures and Cash Market Commentary

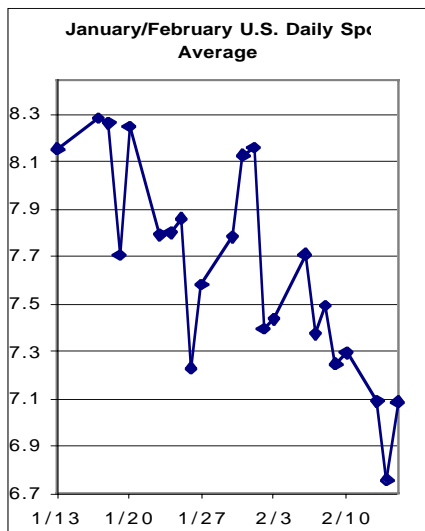
U.S. Daily prices were generally down on Thursday. Prices went down, as most analysts believe that gas inventories are more than adequate to offset cold temperatures. According to the Energy Information Agency data released today, US storage decreased by 102 bcf to 2266 bcf, but the level is still 44 percent above the 5 year average. "People just aren't using gas and that's why we don't have the withdrawals that we usually do," said an expert. "Demand is down considerably."

Henry Hub traded between \$7.0910 and \$7.1770 Thursday averaging \$7.1340, down 20.45 cents from the previous trading day's weighted average of \$7.3385. U.S. Gulf prices traded between \$6.5310 and \$7.0420. Midwest prices averaged \$7.3165 on Thursday, trading between \$7.1810 and \$7.4320.

In the Northeast region, deals in Transco Zone 6 (NY) were done around the \$7.7665 range. Some deals were done as high as \$7.8320, down 12.95 cents from the prior day's average.

In the Western region, California border prices traded between \$6.1394 and \$6.8520, giving it a one-day average of \$6.6246.

NYMEX natural gas futures ended Thursday with March's contract up 6.80 cents to close at \$7.134 in the day's trading session.



U.S. Spot Gas Prices					
Daily U.S. Gas Price Index (US\$/MMBtu): Thursday February 16, 2006					
	Low	High	Index	Last	Chg.
<i>Louisiana Average</i>	6.7110	7.2820	7.0830	7.2121	-0.1291
ANR	7.0010	7.0820	7.0415	7.1410	-0.0995
Columbia, Onshore	7.0960	7.1720	7.1340	7.2810	-0.1470
Columbia, Mainline	7.1210	7.2820	7.2015	7.3810	-0.1795
FGT Z1	7.1610	7.1720	7.1665	7.2910	-0.1245
FGT Z2	7.1510	7.1720	7.1615	7.2910	-0.1295
FGT Z3	7.1610	7.1720	7.1665	7.2910	-0.1245
Henry Hub	7.0910	7.1770	7.1340	7.3385	-0.2045
Transco Z4	7.2010	7.2820	7.2415	7.3960	-0.1545
NGPL (La.)	6.7110	6.8770	6.7940	6.8035	-0.0095
Sonata	7.1110	7.1820	7.1465	7.3360	-0.1895
Tennessee, 500 Leg	6.9510	7.0820	7.0165	7.2610	-0.2445
Tennessee, 800 Leg	6.9510	7.0820	7.0165	7.1760	-0.1595
Texas E. (WLA)	6.9010	7.0070	6.9540	7.0660	-0.1120
Texas E. (ELA)	6.9110	7.0420	6.9765	7.0110	-0.0345
Texas Gas SL	7.0010	7.0670	7.0340	7.0460	-0.0120
Transco Z3, St. 50, 62, 64	7.1410	7.1920	7.1665	7.3310	-0.1645
Trunkline WLA	7.0610	7.0820	7.0715	7.1785	-0.1070
Trunkline ELA	7.0410	7.1020	7.0715	7.1985	-0.1270
<i>Texas Average</i>	6.5310	7.0420	6.8179	6.7789	0.0390
<i>Permian Basin Average</i>	6.5310	6.8070	6.6678	6.4998	0.1680
El Paso	6.5310	6.6820	6.6065	6.4910	0.1155
Tex Intra. Waha	6.6510	6.8070	6.7290	6.5085	0.2205
East Texas Average	6.7010	7.0420	6.8878	6.9460	-0.0583
Texas Eastern (ETX)	6.7010	6.8620	6.7815	6.7310	0.0505
Texas Gas (Z1)	6.9010	7.0420	6.9715	7.0810	-0.1095
Houston Ship Channel	6.8510	6.9820	6.9165	6.9610	-0.0445
Katy Hub Tailgate	6.8210	6.9420	6.8815	7.0110	-0.1295
South Texas Average	6.7010	7.0320	6.8981	6.8909	0.0072
Aqua Dulce Hub	6.8293	6.9587	6.8940	6.8868	0.0072
NGPL (STX)	6.9010	6.9820	6.9415	6.9560	-0.0145
Tennessee	6.8860	7.0320	6.9590	6.9735	-0.0145
Texas Eastern (STX)	6.7010	6.8620	6.7815	6.7310	0.0505
Trunkline South	6.8400	6.9900	6.9144	6.9072	0.0072
<i>Oklahoma/Kansas Average</i>	6.6210	7.2320	6.7714	6.6606	0.1108
ANR	6.6210	6.7420	6.6815	6.6810	0.0005
NGPL (Midcont.)	6.6810	6.8320	6.7565	6.6460	0.1105
NorAm (East)	6.6510	6.8320	6.7415	6.6060	0.1355
Noram (West)	6.6410	6.8220	6.7315	6.5860	0.1455
Demarcation	7.0810	7.2320	7.1565	7.1010	0.0555
Northern (Mid 13)	6.6630	6.7710	6.7171	6.6063	0.1108
Northern (Mid11)	6.6730	6.7830	6.7281	6.6173	0.1108
Northern (Mid 10)	6.6680	6.7800	6.7235	6.6127	0.1108
ONG	6.7510	6.7820	6.7665	6.6010	0.1655
PEPL	6.6510	6.8320	6.7415	6.6060	0.1355
Williams	6.7010	6.7820	6.7415	6.6035	0.1380
<i>New Mexico Average</i>	6.3510	6.6120	6.4815	6.4260	0.0555
El Paso Bondad	6.3510	6.5620	6.4565	6.4010	0.0555
TW SJ (Blanco)	6.4010	6.6120	6.5065	6.4510	0.0555
<i>Rockies Average</i>	6.5510	6.7420	6.6195	6.5180	0.1015
Stanfield	6.5610	6.7420	6.6515	6.6760	-0.0245
Opal	6.5510	6.6620	6.6065	6.4660	0.1405
CIG (N. System)	6.5910	6.6420	6.6165	6.4910	0.1255
DJ Basin	6.5910	6.6420	6.6165	6.4910	0.1255
Northwest, domestic	6.5510	6.6620	6.6065	6.4660	0.1405

Daily U.S. Gas Prices Index continued					
<i>Appalachia Average</i>	7.3710	7.6020	7.5015	7.5927	-0.0912
CNG, North Point	7.4510	7.5720	7.5115	7.5610	-0.0495
CNG, South Point	7.4810	7.6020	7.5415	7.5910	-0.0495
Columbia, App.	7.3710	7.5320	7.4515	7.6260	-0.1745
<i>California Average</i>	6.1394	6.8520	6.6246	6.6216	0.0030
Northern California Average	6.5710	6.7820	6.6765	6.7110	-0.0345
Malin	6.5710	6.7820	6.6765	6.7110	-0.0345
Southern California Average	6.1394	6.8520	6.5726	6.5321	0.0405
Cal Border, Topock	6.6610	6.8520	6.7565	6.7260	0.0305
Cal Border, KRS	6.6310	6.8220	6.7265	6.6760	0.0505
Cal Border, Wheeler Ridge	6.1390	6.3300	6.2349	6.1944	0.0405
<i>Midwest Average</i>	7.1810	7.4320	7.3165	7.2835	0.0330
Ventura	7.2710	7.4320	7.3515	7.2960	0.0555
Chicago	7.1810	7.3820	7.2815	7.2710	0.0105
NGPL Iowa-Ill. receipt	7.2260	7.4070	7.3165	7.2835	0.0330
<i>Michigan Average</i>	7.2910	7.3770	7.3340	7.4660	-0.1320
Mich-Consum. Power	7.2910	7.3770	7.3340	7.4660	-0.1320
Mich-Mich Con	7.2910	7.3770	7.3340	7.4660	-0.1320
<i>Northeast Average</i>	7.2510	8.0682	7.7344	7.8146	-0.0802
Texas E., M-3	7.7010	7.8320	7.7665	7.8460	-0.0795
Transco Zone 6 (non NY)	7.6510	7.7820	7.7165	7.8760	-0.1595
Transco Zone 6 (NY)	7.7010	7.8320	7.7665	7.8960	-0.1295
New England Citygate	7.9400	8.0700	8.0040	8.0935	-0.0895
Dracut	7.5660	7.6920	7.6290	7.6635	-0.0345
Algonquin	7.8810	7.9820	7.9315	8.0210	-0.0895
Alliance	7.2510	7.4020	7.3265	7.3060	0.0205
US Daily Average	6.1394	8.0682	7.0284	7.0374	-0.0090

Source: Enerdata Ltd. Volume and Price Survey
 Note: All prices reported were transacted on the above date. Index prices are weighted (by volume) average prices. All One-Day prices reported have flow times commencing the day

...continued from page 5

EIA Releases 2006 Outlook; Implications for the Natural Gas Industry

EIA released in mid-February the 2006 Annual Energy Outlook. Total consumption of natural gas in the AEO2006 reference case is projected to increase from 22.4 trillion cubic feet in 2004 to 27.0 trillion cubic feet in 2025, 3.7 trillion cubic feet lower than projected in the AEO2005 reference case, mostly as a result of higher natural gas prices. After peaking at 27.0 trillion cubic feet in 2024, natural gas consumption is projected to fall slightly by 2030, as higher natural gas prices result in a larger market share for coal in the electric power sector in the later years of the projection. The projected growth in natural gas demand in AEO2006 results primarily from increased use of natural gas for electricity generation and industrial applications, which together account for 62 percent of the projected demand growth from 2004 to 2025. In addition, demand for natural gas in the residential and commercial sectors is projected to grow by 1.5 trillion cubic feet in total from 2004 to 2025. (than the AEO2005 projection).

In the AEO2006 reference case, the projected average prices of natural gas and coal delivered to electricity generators in 2025 are, respectively, 31 cents and 11 cents per million Btu higher than the comparable prices in AEO2005. Although the projected levels of coal consumption for electricity generation in 2025 are similar in the two forecasts, higher natural gas prices and slower growth in electricity demand in AEO2006 lead to significantly lower levels of natural gas consumption for electricity generation. As a result, projected cumulative capacity additions and generation from natural-gas-fired power plants are lower in the AEO2006 reference case, and capacity additions and generation from coal-fired power plants from 789 billion kilowatt hours in 2004 to 871 billion kilowatt hours in 2030 in the AEO2006 reference case, accounting for about 15 percent of total generation in 2030.

Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the AEO2006 reference case, increasing from 8.6 million barrels per day in 2004 to a peak of 10.5 million barrels per day in 2021, then declining to 10.4 million barrels per day in 2025 and remaining at about that level through 2030. The AEO2005 projection for total domestic petroleum supply in 2025 was lower, at 8.8 million barrels per day.

Total domestic natural gas production, excluding supplemental natural gas supplies, increases from 18.5 trillion cubic feet in 2004 to 21.6 trillion cubic feet in 2019, before declining to 20.8 trillion cubic feet in 2030 in the AEO2006 reference case. In 2025, domestic natural gas production is projected to be 21.2 trillion cubic feet, compared with 21.8 trillion cubic feet in the AEO2005 reference case. The lower level of domestic natural gas production in the AEO2006 reference case is entirely attributable to lower levels of offshore production. Offshore natural gas production in 2025 is lower in the AEO2006 reference case than it was in AEO2005, due at least in part to the impacts

Futures Prices										
Natural Gas Futures										
Feb-16-06	Nymex Henry Hub					Current Month		NYMEX Trading Summary		
	High	Low	Settle	Last	Chg.	Trading Summary	Month	Avg.	3-Day	
06MAR	7.230	6.980	7.134	7.066	0.068	Date	Settle	Jan-04	6.399	6.224
06APR	7.405	7.180	7.308	7.249	0.059	30-Jan	9.389	Feb-04	6.364	5.739
06MAY	7.540	7.340	7.458	7.399	0.059	31-Jan	9.316	Mar-04	5.376	5.118
06JUN	7.660	7.460	7.585	7.524	0.061	1-Feb	8.723	Apr-04	5.504	5.365
06JUL	7.780	7.600	7.710	7.647	0.063	2-Feb	8.347	May-04	5.755	5.858
06AUG	7.850	7.670	7.790	7.722	0.068	3-Feb	8.613	Jun-04	6.337	6.690
06SEP	7.910	7.740	7.855	7.787	0.068	6-Feb	7.995	Jul-04	6.367	6.326
06OCT	8.000	7.820	7.945	7.869	0.076	7-Feb	7.858	Aug-04	6.054	5.998
06NOV	8.810	8.710	8.810	8.729	0.081	8-Feb	7.735	Sep-04	5.562	5.190
06DEC	9.680	9.530	9.640	9.554	0.086	9-Feb	7.479	Oct-04	5.058	5.459
07JAN	10.180	10.050	10.180	10.089	0.091	10-Feb	7.316	Nov-04	7.195	7.973
07FEB	10.180	10.090	10.190	10.109	0.081	13-Feb	7.243	Dec-04	7.706	7.177
07MAR	10.000	9.900	10.000	9.939	0.061	14-Feb	7.114	NYMEX Trading Summary		
07APR	8.370	8.200	8.310	8.334	-0.024	15-Feb	7.066	1992-2003		
07MAY	8.200	8.080	8.130	8.169	-0.039	16-Feb	7.134	1992	1.770	
07JUN	8.270	8.229	8.190	8.229	-0.039	17-Feb		1993	2.150	
07JUL	8.299	8.210	8.260	8.299	-0.039	20-Feb		1994	1.920	
07AUG	8.364	8.280	8.320	8.364	-0.044	21-Feb		1995	1.630	1.62
Strips	Avg.	Avg.	Avg.	Avg.	Avg.	22-Feb		1996	2.410	2.550
3 Months	7.392	7.167	7.300	7.238	0.062	23-Feb		1997	2.590	2.630
Mar/06-Oct/06	7.672	7.474	7.598	7.533	0.065	24-Feb		1998	2.220	2.140
12 Month	8.352	8.181	8.300	8.229	0.072			1999	2.270	2.270
18 Month	8.429	8.282	8.379	8.338	0.041			2000	3.760	3.910
Summer*	7.735	7.544	7.664	7.600	0.065			2001	4.544	4.384
Winter*	9.770	9.656	9.764	9.684	0.080	Average	7.952	2002	3.165	3.252
Sum/Win**	-2.035	-2.112	-2.100	-2.084	-0.015	3-Day		2003	5.355	5.441

* Summer includes Apr-Oct, Winter includes Nov-Mar
 ** Summer, Winter spread.

of Hurricanes Katrina and Rita, which are expected to delay offshore drilling projects because of a lack of rigs and to have a long-term effect on production levels as a result of the slow recovery of production from existing fields.

Lower 48 offshore production is projected to fall slightly from the 2004 level of 4.3 trillion cubic feet and then grow steadily through 2015, peaking at 5.1 trillion cubic feet as new resources come on line in the Gulf of Mexico. After 2015, lower 48 offshore production declines to 4.3 trillion cubic feet in 2025 and 4.0 trillion cubic feet in 2030. In the AEO2005 reference case, offshore natural gas production was projected to increase more quickly and reach higher levels, peaking at 5.3 trillion cubic feet in 2014 before falling to 4.9 trillion cubic feet in 2025. The projection for onshore production of natural gas is also generally lower for most of the projection period in the AEO2006 reference case than was projected in AEO2005. In the later years of the AEO2006 reference case, however, with higher natural gas prices, onshore production grows strongly, to 14.7 trillion cubic feet in 2025, equal to the AEO 2005 projection. Projected onshore production in AEO2006 remains at the 2025 level through 2030.

Lower 48 production of unconventional natural gas is expected to be a major contributor to growth in U.S. natural gas supplies. Unconventional natural gas production is projected to account for 45 percent of domestic U.S. natural gas production in 2030, as compared with the AEO2005 reference case projection of 39 percent in 2025. In AEO2006, however, unconventional natural gas production is lower in the mid-term (between 2006 and 2020) than was projected in AEO2005. The lower levels of production in AEO2006 before 2021 reflect a decline in overall natural gas consumption in response to higher prices. Starting in 2021, the projected levels of unconventional natural gas production in the AEO2006 reference case are higher than those in AEO2005, reaching 9.5 trillion cubic feet in 2030.

Construction planning for the Alaska natural gas pipeline is expected to start soon, and the new pipeline is expected to be completed by 2015. When the pipeline goes into operation, Alaska's total natural gas production is projected to increase to 2.2 trillion cubic feet in 2025 (from 0.4 trillion cubic feet in 2004), the same level as projected in the AEO2005 reference case.

The projection for net U.S. pipeline imports of natural gas from Canada and Mexico (predominantly Canada) in the AEO2006 reference case in 2025 is 1.3 trillion cubic feet lower than was projected in AEO-2005. AEO2006 projects a continued decline in net pipeline imports, to 1.2 trillion cubic feet in 2030, as a result of depletion effects and growing domestic demand in Canada. The AEO2006 reference case reflects an expectation that growth in Canada's unconventional natural gas production (primarily from coal seams) will not be adequate to offset a decline in conventional production in Alberta, based in part on data and projections from Canada's National Energy Board and other sources.

Growth in LNG imports is projected to meet much of the increased demand for natural gas in the AEO2006 reference case, but the increase is less than was projected in the AEO2005 reference case. The growth in LNG imports is moderated by three factors: higher natural gas prices reduce domestic consumption; higher world oil prices increase worldwide demand for natural

gas and LNG imports, which raises the price of LNG; and, to a lesser extent, higher world oil prices lead to higher foreign demand for GTL production, which uses more natural gas as a feedstock, further increasing the price pressure on natural gas and LNG. Except for expansions of three of the four existing onshore U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana), the completion of U.S. terminals currently under construction, and the addition of new facilities to serve the Gulf Coast, Southern California, Florida, and New England, no other new facilities are projected to be built to serve U.S. markets in the AEO2006 reference case.

Total net imports of LNG to the United States in the AEO2006 reference case are projected to increase from 0.6 trillion cubic feet in 2004 to 4.1 trillion cubic feet in 2025 (about two-thirds of the import volumes projected in the AEO2005 reference case) and to 4.4 trillion cubic feet in 2030. In some of the AEO2006 alternative cases, however, particularly those with relatively higher natural gas prices, additional LNG imports and new terminals are projected.

CERA Predicts \$62/Bbl Average 2006 Crude Price

A combination of political risk and new fuel specifications should keep benchmark crude oil futures above \$60 during 2006, according to a forecast released by the Cambridge Energy Research Associates (CERA) in February.

Presenting the 2006 oil outlook at the CERA's conference, James Buckhard, CERA senior director and head of global oil market analysis, said despite a host of factors that should be pushing prices down these "specification changes along with geopolitical risk are likely to keep prices above \$60 at about \$62 on an annual average basis", Dow Jones informs.

"Fear of what could go wrong will continue to be in play throughout the year," he said. The energy consultancy's prediction is a more bullish forecast compared with recent years, when it has emphasized the growth in output from countries not in the Organization of Petroleum Exporting Countries. Buckhard said crude and gasoline inventories have recovered somewhat in recent months. This may continue, but it will have a limited impact because of political uncertainty and potential disruptions from the new fuel specifications.

Buckhard noted that in general price targets among producing nations have also been a factor in keeping prices high. "Given their influence in the market, they will maintain a strong role in keeping prices near their objectives," he said. Oil prices soared in 2004 and 2005, hitting a record high just north of \$70 as Hurricane Katrina slammed into the U.S. Gulf Coast late last summer.

Benchmark futures on Nymex were close to the record again last month, after violence in Nigeria left a sizable portion of that country's light sweet crude oil output offline. Fears of a potential disruption in supply from Iran, the second largest exporter in OPEC, have also preoccupied many market participants pushing prices higher last month before they began receding again.

The International Atomic Energy Agency referred Iran to the U.N. Security Council at the beginning of February, because of concerns about its nuclear program. The biggest factor in the high

floor for oil prices will be Iran, for which "we don't see good options," said CERA Middle East analyst Vera de Ladoucette. She endorsed Russia's plan to essentially manage Iran's nuclear program as the best in a series of bad options. De Ladoucette said a retreat by the West would empower Iran, while a military strike is the "worst" outcome because it would unify Iran's leadership. "The war of words is going to continue and will drive the uncertainty of the market," de Ladoucette said.

CERA analysts reported a mixed bag as far as other regions, with stronger growth in the Caspian helping to supplement Russia, where production growth is slowing. Saudi Arabia's production growth will easily meet - and could best - the mid-2009 timeframe to reach 12.5 million barrels. But the energy outlook remains murky for Iraq, where the industry will continue to struggle, even if the country is ultimately able to stabilize and defeat the insurgency.

The March crude contract on the Nymex fell 54 cents in trading Wednesday to \$62.55 a barrel. Beyond 2006, Buckhard said there is potential for production capacity growth through 2010. However, the growing concentration of energy production is in fewer countries, many of which are politically unstable. As a result, CERA doesn't see a return to the lower price environment of 1986-2004, he said.

Liquefied natural gas could comprise as much as 25% of U.S. natural gas supply by 2020, a Cambridge Energy Research Associates analyst said last week. "Life begins at 40," said CERA analyst Michael Zwenker at a CERA energy conference here, referring to the 40 years it has taken for LNG liquefaction plants in the U.S. to be a major part of the gas industry. Zwenker pointed to Europe and Asia already being squeezed by the need to buy LNG to supplement their energy sources. "Countries are in need of gas," he said. "They are being outbid for LNG." He said by 2020, nearly 20% of the global energy supply will be LNG. He pointed to new energy projects totaling nearly \$200 billion in costs. His comments echo others at the CERA conference who have pointed to the growth in the LNG markets as one of the most dynamic forces shaping the energy markets.

Williams, Pacific Gas and Electric Company and Fort Chicago Energy Partners L.P. Propose Major New Gas Transmission Pipeline Project

Williams' Northwest Pipeline, Pacific Gas and Electric Company and Fort Chicago Energy Partners L.P. have agreed to jointly pursue the development of a major new gas transmission pipeline that would increase natural gas supplies for the West Coast of the United States. The three participants will hold equal interests in the pipeline project.

The proposed Pacific Connector Gas Pipeline, a 250-mile natural gas transmission line, together with the proposed Jordan Cove liquefied natural gas terminal in Coos Bay, Ore., being developed by Fort Chicago, are designed to bring new diverse worldwide natural gas supply sources to West Coast markets.

Scheduled for completion in 2010, the project would provide competitive and reliable alternatives to existing supplies from Canadian, Southwest and Rocky Mountain sources, which are increasingly being pursued to supply eastern U.S. markets. The

Pacific Connector would link the proposed Jordan Cove LNG terminal to Williams' Northwest Pipeline system near Roseburg, Ore., and the Tuscarora and PG&E gas transmission systems, both near Malin, Ore.

The project's Oregon location enhances supply options for consumers in Oregon, Washington and throughout the Pacific Northwest. As proposed, the pipeline would be capable of delivering 1 billion cubic feet of natural gas per day to the Pacific Northwest and beyond - including California and northern Nevada - through various interconnects with the pipelines previously mentioned. Today, virtually all of the supplies serving the Pacific Northwest and northern California originate in the Rocky Mountains or in Canada.

The group immediately will begin seeking regulatory approvals and market commitments for the Pacific Connector and plans to begin environmental assessments along the proposed route in March. The group is targeting a Federal Energy Regulatory Commission application filing for the pipeline by January 2007. "Providing access to diverse, abundant natural gas supplies continues to be a major focus at Williams," said Phil Wright, senior vice president of Williams' gas pipeline business. "The Pacific Connector is designed to give customers access to LNG supplies, further enhancing the superior supply flexibility offered by our own Northwest system."

"The Pacific Connector is an example of the innovative options PG&E is pursuing to bring much needed supplies to the region," said Bob Howard, PG&E's vice president of gas transmission and distribution. "Through joining forces with other utilities in the region, we hope to bring additional cost-effective supply sources that would significantly benefit our gas and electric end use customers."

Stephen White, president and CEO of Fort Chicago, commented: "We are extremely pleased to have these pre-eminent energy companies join us in this natural gas transportation project. Their participation should ensure optimal pipeline and market interconnectivity, and their collective strengths help to form a foundational bridge between the Jordan Cove LNG terminal and the substantial markets located throughout the Pacific Northwest, California and elsewhere in the western U.S."

Natural Gas News

TransCanada Files for Expansion Certificate for North Baja Pipeline

TransCanada Corporation announced on February 9 the filing by its subsidiary, North Baja Pipeline LLC, of an application with the Federal Energy Regulatory Commission (FERC) for a certificate for a two-phase expansion of its existing natural gas pipeline in southern California and the construction of a new pipeline lateral in California's Imperial Valley. The expansion project envisions substantially increasing the capacity of the existing pipeline and allowing for bi-directional flow of natural gas. Gas currently flows on North Baja Pipeline southward from its interconnection with El Paso Natural Gas Company at Ehrenberg, Arizona.

The proposed North Baja Pipeline expansion links to a

corresponding expansion of the Gasoducto Bajanorte line in Mexico owned by Sempra Energy. Together, the expansions will allow for import into the United States of up to 2.7 billion cubic feet a day (Bcf/d) of natural gas supplied from several potential liquefied natural gas (LNG) terminals near Baja California, Mexico, including the Costa Azul terminal that is currently under construction. Shippers have indicated their commercial support for the projects by signing precedent agreements in support of the expansion plan as filed with the FERC.

"We are pleased to be involved in the first major point of entry for regasified LNG on the West Coast of North America," said Hal Kvisle, TransCanada's chief executive officer. North Baja Pipeline proposes construction of up to 80 miles of 42- and 48-inch-diameter pipeline, predominantly in the existing right of way in La Paz County, Arizona, and in Riverside and Imperial counties, California.

In addition to the expansion, North Baja Pipeline is seeking a certificate for a new 46-mile, 16-inch-diameter lateral to serve the Imperial Irrigation District (IID). The lateral would deliver up to 103 million cubic feet per day (MMcf/d) of natural gas from North Baja Pipeline's mainline to serve the IID's El Centro Generating Station.

The expansion and the IID lateral will be constructed in phases. Phase I would reverse the flow of gas on the pipeline system. Plans call for a new meter station at an interconnect with Southern California Gas Company in Blythe, California, various modifications to the existing compressor station in Ehrenberg, and changes to the existing Ogilby Meter Station in Imperial County. This phase would be in service in late 2007. Also part of Phase I is the IID Lateral which is expected to go into service in mid 2009.

Phase II, which is contingent upon the continued development and approval of LNG facilities in Mexico, involves the construction of the new line parallel to North Baja Pipeline's existing mainline system and the installation of seven new mainline valves. It is anticipated to be in service in late 2009. If all phases proceed, the total estimated capital cost is anticipated to be approximately US\$291 million.

In addition to its FERC certificate of public convenience and necessity (which includes a determination on environmental issues), the project will need various permits and leases from the federal Bureau of Land Management, the California State Lands Commission, and other agencies.

US Tribes To Give Land Testimony In Right-Of-Way Hearing

Public testimony from North American native tribes on the value of their lands and the determination of right-of-way will be held March 7-8 in Denver, Dow Jones informs. The testimony will have implications on talks involving El Paso Natural Gas and the Navajo Nation regarding gas pipelines on Navajo land. The U.S. Department of Energy will lead the two-day public scoping or testimony, which will also deal with sovereignty and self-determination of the native American tribes. A number of U.S. tribes are slated to give testimony at the two-day session at the Adams Mark Hotel in downtown Denver. The DOE will present a report on the testimony and its conclusions by August 7. The

session is mandated by Section 1813 of the Energy Policy Act of 2005.

El Paso Natural Gas Co., a wholly owned subsidiary of El Paso Corp. (EP), has entered into an extension of talks with the Navajo Nation through this year on a contract to extend EPNG's right-of-way across Navajo land. The Navajo Nation and El Paso disagree as to what constitutes fair consideration for a long-term extension of the right of way. The arrangement allows more time for the parties to negotiate. "The talks are ongoing," said El Paso spokesman Richard Wheatley.

The tribe's right-of-way encompasses about 900 miles of gas pipelines on Navajo lands in New Mexico and Arizona. The company has paid the Navajo nation \$29 million over the past 20 years for the expiring right of way, according to El Paso. In early October 2005, the company made what it called a final offer to the tribe of \$138 million in cash. El Paso added a non-cash consideration of roughly another \$60 million concerning power purchases and a helium gas energy project on the Navajo Nation's land.

Tribal lands and government lands are the only rights-of-way that come under such renewals, according to El Paso spokesman Bruce Connery at the time. He put tribal lands rights-of-way prices at \$100-\$500/acre, with the land selling at \$500-\$1,500/acre. Negotiations with the Navajo Nation have been under way since early 2004, El Paso said. The pipelines were installed across the Navajo nation around a half-century ago, according to El Paso.

The company contends any increased payments to the tribe will increase costs of gas transportation to the Southwest and California customers. The El Paso Natural Gas pipeline extends from San Juan, Permian, and Anadarko Basins to markets in California, Arizona, Nevada, New Mexico, Oklahoma, Texas, and northern Mexico. The Navajo Nation reservation extends for about 15-17 million acres over New Mexico, Arizona and Utah and is about the size of West Virginia. About 300,000 Navajos live on the reservation.

AGA Executive Commends Senate Energy Committee for Continued Focus on Natural Gas Supply

Congress must act decisively this year to expand the ability of energy producers to find and retrieve natural gas, such as in a particularly promising portion of the Gulf of Mexico, or risk continued high prices that have plagued families and factories, according to testimony presented before a Senate committee by the American Gas Association (AGA) on February 16.

"The average residential customer is paying roughly twice as much for natural gas as he did in 1999. These high prices strain the budgets of all homeowners and, even worse, many low-income households must choose between heat and other life necessities," said Thomas Skains, chairman, president and CEO of Piedmont Natural Gas in testimony before the U.S. Senate Committee on Energy and Natural Resources. Skains is a member of AGA's Board of Directors.

By law, utilities do not profit from higher commodity prices. "In fact, higher natural gas prices hurt our business. We want what our customers want: adequate supplies at affordable prices," Skains said.

The purpose of the hearing was to gather public input on S. 2253, which would require the U.S. Secretary of the Interior to offer certain portions of the 181 area for natural gas and oil leasing.

"I urge you to act here and now to begin to rectify the natural gas supply and demand imbalance. Opening Lease Sale 181 in the Gulf of Mexico is an important step in the right direction," Skains said. "There is absolutely no question we must do this. Natural gas is being produced in a safe, efficient and environmentally responsible fashion. We are talking about activity 100 miles or more offshore that will not be seen, heard or smelled. No tankers, no barges, no spills. I live in a coastal state, and I appreciate the need to protect our beaches, but I know this is no threat."

"Energy efficiency must continue to play a key role in easing the price pressure in natural gas markets, but it is not the only answer," Skains emphasized. "Prices will come down only when we increase the supply of natural gas in the marketplace to meet the growing demand for our product. We must unlock more domestic sources of natural gas, both onshore and offshore. We must begin construction of a natural gas pipeline from Alaska. We must build new LNG receiving terminals, and not just in the Gulf Coast. Hurricanes Katrina and Rita taught us an important lesson about the need for geographical diversity for our nation's natural gas supply. Further, the mix of fuels used to generate electricity must be diversified, including the use of solar and wind technologies, the use of clean coal and coal gasification and nuclear power."

Proposed Federal 5-Year Plan for Offshore Energy Moves Toward Greater Natural Gas Supply But Needs Work According to AGA

The proposal by the U.S. Interior Department of a five-year plan for developing energy resources from offshore areas under federal control would help reduce natural gas prices by getting more natural gas to market, and should be expanded, the American Gas Association reported on February 8. "Given the environmental and economic benefits of using natural gas, and the dramatic increases in natural gas prices due to tight supply conditions, we are pleased that the Minerals Management Service will foster public discussion about how our country's abundant offshore natural gas resources should be developed between 2007-2012," said Tom Moskitis, AGA managing director for external affairs.

An enormous amount of natural gas (633 trillion cubic feet) is technically recoverable from the Outer Continental Shelf, the MMS said. This is enough to support the United States natural gas needs by itself for more than 30 years, based on average 22 Tcf annual consumption. Today, MMS asked for public comments on its 2007-2012 Outer Continental Shelf proposal, which would offer 21 lease sales in seven planning areas, including a portion of the "Sale 181" area off of Louisiana as well as study a deepwater area to the south. The proposal would also study the potential for natural gas and oil development off Virginia's coast. This responds, in part, to AGA's recommendation that moratoria areas on the OCS be included in the draft plan. The Outer Continental Shelf proposal would prohibit energy leases within 100 miles of the Florida coast that used to be part of the Eastern

Gulf of Mexico Planning Area and realign the boundaries of its Central Gulf of Mexico Planning Area to correspond with new federal OCS offshore areas announced in early January 2006.

"To those who oppose further offshore energy production, we have a simple question: What's YOUR plan to boost natural gas supplies, given the substantial environmental benefits of natural gas and the fact that energy efficiency by itself is not sufficient to meet soaring demand for natural gas by homes, factories and electric power plants?" Moskitis said.

Most of the natural gas consumed in the United States (84 percent) is produced in the U.S.; the remainder is imported via pipelines from Canada (13 percent) and via tanker ships as liquefied natural gas (3 percent). U.S. homes and businesses pay more for natural gas than nearly anyone in the world because producers cannot keep pace with rising demand for natural gas, AGA said.

California Public Utilities Commission Moves To Cut Greenhouse Gas Emissions

California's biggest electric utilities eventually will have to reduce their emissions of various gases thought to contribute to global warming, according to a plan approved unanimously Thursday by the California Public Utilities Commission, Dow Jones informs.

Most details, such as what the emission limits will be and what the penalties will be for exceeding the limits, are to be determined. The plan sets 1990 as the preferred baseline year, in line with the international Kyoto protocol for reducing greenhouse gas emissions, and calls for some measured reduction from a baseline year. The emissions to be limited include carbon dioxide and methane. The state's plan should be designed to work within whatever cap-and-trade system, like that now used nationally for sulfur dioxide, is developed nationally or internationally for greenhouse gases.

The plan will affect the state's three investor-owned utilities - Edison International's Southern California Edison, PG&E Corp.'s Pacific Gas & Electric Co., and Sempra Energy's San Diego Gas & Electric Co. It will also impact competitive power companies, like NRG Energy Inc. and Reliant Energy Inc., which supply electricity to customers within the regulated utilities' districts as well as to the utilities themselves.

The rule has no impact on publicly owned utilities, like the Los Angeles Department of Water & Power, over which the utilities commission has little authority. The legislature, however, is moving to impose similar rules on such municipal utilities, and Gov. Arnold Schwarzenegger has endorsed the state's moving to reduce greenhouse gas emissions. California joins some nine states in the northeast in an effort to reduce such emissions despite the federal government's refusal to ratify the Kyoto treaty.

FERC: Warm Weather Kept Prices Low but Increased Generation May Increase Gas Prices

Warm weather this winter has helped the country dodge a potential natural gas supply shortage, but increased generation from power plants fueled by natural gas could bolster prices in the coming months, staff at the U.S. Federal Energy Regulatory Commission said in mid-February, quoted by Dow Jones.

At the commission's monthly open meeting, FERC analysts said the Gulf of Mexico's natural gas supply infrastructure was compromised by hurricanes Katrina and Rita. Without the winter's record warm weather, Americans could have seen soaring natural gas and electricity prices. "After starting the winter in a strong inventory position but with real concerns as to the availability of supply from the Gulf for the winter, our literally 1-in-100 chance warm weather has resulted in a current surplus of gas inventory," said Steve Harvey of the FERC's Office of Market Oversight and Investigations. "We bet, as a country, on mild weather, and we hit the jackpot."

The price of natural gas futures on Nymex has fallen consistently from a high over \$15 per million British thermal units in the middle of December to the current price of \$7.20/MMBtu, mainly because of the record warm temperatures. Contributing to the decline, Harvey said, is an apparent small reduction in energy consumption as consumers reacted to high energy prices at the beginning of the winter. There also may have been a supply response to high prices, Harvey said, as a number of natural gas producing basins in the continental U.S. saw significant increase in production.

Despite the bearish trend in gas prices, the continued construction of power plants fueled by natural gas may help support the market in the near future, Harvey said. That may be why gas futures prices for next winter are still trading over \$10, he said. "Another summer of strong electric demand growth for natural gas, like last year, may be a factor in current futures prices," Harvey said.

KeySpan In Talks On Possible Sale

KeySpan Corp. confirmed on February 17 that it is discussing a merger or takeover with several companies but said it probably will disclose details until its board either approves a deal or terminates the talks, Dow Jones reports. Brooklyn-based KeySpan has already attracted offers exceeding \$6.5 billion, with Consolidated Edison Inc. and the U.K.'s National Grid PLC (NGG) believed to be the leading bidders, the New York Times said Friday.

Investment bank Lazard Ltd. is advising KeySpan, which was an existing client of the bank, a person familiar with the relationship said. KeySpan is one of the largest natural gas distributors in the

U.S. and the largest in the Northeast, with gas utilities in New York, Massachusetts and New Hampshire serving 6 million customers. It's also the largest power generator in New York State, with about 6,650 megawatts of generating capacity that supplies roughly 25% of New York City's capacity needs and 1.1 million customers on Long Island.

News that KeySpan has put itself up for sale comes shortly after Southern Union Co. announced the sale of New England Gas Co., its Rhode Island local distribution company, to National Grid for \$575 million, including the assumption of \$77 million in debt. National Grid has power distribution operations in New England and owns Niagara Mohawk Power Corp., which provides electricity to 1.5 million customers and natural gas to 560,000 customers in upstate New York.

Consolidated Edison provides electric, gas and steam service to more than three million customers in New York City and Westchester County and provides energy services to also parts of New York, northern New Jersey and northeastern Pennsylvania.

According to Dow Jones, if a KeySpan deal materializes, it would be the latest in a wave of consolidation in the regulated utility industry that began in December 2004 when Exelon Corp. announced plans to buy Public Service Enterprise Group Inc. A KeySpan deal would be the first to be announced since the actual repeal of PUHCA in early February, although the repeal was authorized in the national energy bill last year.

"We have noted a lack of organic EPS growth drivers for KSE... and have been dubious about KSE's prospects for utility rate relief," analyst Craig Shere of Calyon Securities said in a note. He noted also that KeySpan's Chairman and Chief Executive Bob Catell is 69, "one of the most tenured executives in the industry."

The premium KeySpan gets will not approach the multiple of 10 times earnings before interest, taxes, depreciation and amortization National Grid agreed to pay for New England Gas, said Shere of Calyon Securities. Both utilities that Southern Union recently put on the auction block have opportunities for rate relief on top of the merger-related savings expected to be realized by the acquirers, he said.

According to Times, KeySpan is unlikely to fetch much more than \$40 a share, as premiums for power takeovers have fallen sharply despite rising electricity prices.