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January 4, 2010

RECEIVED

JAN 05 2010

PUBLIC SERVICE COMMISSION

Executive Secretary
North Dakota Public Service
Commission
State Capitol Building
Bismarck, ND 58505

Re: Cost of Gas Adjustment (COG)
January 2010

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and seven (7) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (46th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (46th Revised Sheet No. 8), showing the January 2010 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of \$1.4113 per mcf for residential and firm general service customers and \$0.7858 per mcf for interruptible customers.

Attachment B shows the calculations supporting the gas costs for January 2010, including the calculation of the commodity cost of gas. The commodity cost of gas has increased \$0.7858 per mcf since the last COG filing due to an increase in the market price of gas. There has been an increase in pipeline charges of \$0.6255 per mcf due to changes in pipeline charges. The net effect of these changes is an increase of \$1.4113 per mcf for residential and firm general service customers.

Attachment C explains the reasons for the change in the market price of gas.

Attachment D shows the calculation of the balancing account since April 30, 2009.

Great Plains submitted a check for \$600.00 on December 30, 2008 pursuant to the requirements of Section 49-05-05 of the North Dakota Century Code. This payment covers the \$50.00 filing fee associated with this month's COG filing.

Great Plains respectfully requests this filing be accepted as being in full compliance with the filing requirements of this Commission.

Please acknowledge receipt by stamping or initialing the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Rita A. Mulkern

Rita A. Mulkern
Regulatory Analysis Manager

Attachments

Attachment A

Attachment A



GREAT PLAINS NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2
 46th Revised Sheet No. 1.1
 Canceling 45th Revised Sheet No.1.1

RATE SUMMARY SHEET

Page 1 of 1

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge	COG Items	Total Rate/MCF
Firm Gas Service - General	2	\$3.50 per month	First 10 MCF \$1.2740 Over 10 MCF 1.0540	\$8.8320	\$10.1060 9.8860
Interruptible Gas Service - General	3	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411	\$4.7133	\$5.8524 5.6064 5.4544
Interruptible Gas Service - Grain Processing	4	\$3.50 per month	All MCF \$1.2391	\$4.7133	\$5.9524
Transportation Service	5	\$3.50 per month	First 400 MCF \$1.1391 Next 2,600 MCF 0.8931 Over 3,000 MCF 0.7411		\$1.1391 0.8931 0.7411

Date Filed: January 4, 2010

Effective Date: January 1, 2010

Issued By: Donald R. Ball
 Vice President - Regulatory Affairs

Case No.:



GREAT PLAINS NATURAL GAS CO.
A Division of MDU Resources Group, Inc.

**State of North Dakota
 Gas Rate Schedule**

NDPSC Volume 2
 46th Revised Sheet No. 8
 Canceling 45th Revised Sheet No. 8

COST OF GAS

Summary:	Firm			Interruptible			
	Est. Wtd. Demand	Average	GCR	Est. Wtd. Total	Average	GCR	Total
	Costs	Commodity	Adj.	Firm	Commodity	Adj.	Int.
Base Rate	\$0.0658	\$5.1191	\$0.0000	\$5.1849	\$5.1191	\$0.0000	\$5.1191
Accumulated Adj.	2.4512	(0.4497)	0.2343	2.2358	(0.4497)	(0.7419)	(1.1916)
Current Adj.	0.6255	0.7858	0.0000	1.4113	0.7858	0.0000	0.7858
Total Adj.	3.0767	0.3361	0.2343	3.6471	0.3361	(0.7419)	(0.4058)
Total Rate:	\$3.1425	\$5.4552	\$0.2343	\$8.8320	\$5.4552	(\$0.7419)	\$4.7133

Date Filed: January 4, 2010

Effective Date: January 1, 2010

Issued By: Donald R. Ball
 Vice President – Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2010

<u>Firm</u>	<u>Billing</u> <u>Determinants</u>	<u>Rate</u>	<u>Demand</u> <u>Months</u>	<u>Amount</u>	<u>Amount</u> <u>Per dk</u>
FT-A	7,841	\$3.4671	12	\$326,226	\$0.2084
FT-A - Zone 1-1	500	3.4671	5	8,668	0.0055
FT-A - Zone 1-2	4,500	4.5871	5	103,210	0.0659
FT-A Seasonal	3,000	3.7671	5	56,507	0.0361
TFX Seasonal	3,000	15.1530	5	227,295	0.1452
NOVA - Demand Charge	7,947	16.5434	12	1,577,645	1.0077
Trans Canada - Demand Charge	7,947	16.3863	12	1,562,663	0.9981
BP Canada - Demand Charge	7,947	0.9612	12	91,664	0.0586
NOVA - Seasonal	5,068	16.5434	5	419,210	0.2678
Trans Canada - Seasonal	5,068	16.3863	5	415,229	0.2652
BP Canada - Seasonal	5,068	0.9612	5	24,357	0.0156
BP Canada Winter Surcharge	5,068	3.0417	5	77,077	0.0492
LMS Demand	2,500	1.0000	12	30,000	0.0192
Total Demand Charges				\$4,919,751	3.1425
Estimated Weighted Average Commodity Cost	1,565,565	1/ 5.4552		8,540,470	5.4552
Gas Cost Reconciliation Adjustment					0.2343
Total Current Firm Gas Cost				<u>\$13,460,221</u>	<u>8.8320</u>
Base Cost of Gas					5.1849
Accumulated Adjustment					<u>\$3.6471</u>
<u>Interruptible</u>					
Estimated Weighted Average Commodity Cost					\$5.4552
Gas Cost Reconciliation Adjustment					(0.7419)
Total Current Interruptible Gas Cost					<u>4.7133</u>
Base Cost of Gas					5.1191
Accumulated Adjustment					<u>(\$0.4058)</u>

1/ Authorized in MN Docket No. G004/GR-04-1487 plus Wahpeton volumes.

**GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
JANUARY 2010**

Rates Effective January 1, 2010	<u>\$/Dk</u>	
FT-A - Zone 1-1	\$3.4671	Per dk/Mo.
FT-A - Zone 1-2	4.5871	Per dk/Mo.
FT-A - Seasonal	3.7671	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
NOVA - Demand Charge	16.5434	Per dk/Mo.
Trans Canada Pipeline Demand Charge	16.3863	Per dk/Mo.
BP Canada - Demand Charge	0.9612	Per dk/Mo.
NOVA - Seasonal	16.5434	Per dk/Day
Trans Canada - Seasonal	16.3863	Per dk/Mo.
BP Canada - Seasonal	0.9612	Per dk/Mo.
BP Canada Winter Surcharge	3.0417	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	5.4552	Per dk

Base Rate Effective September 1, 1981

Demand Charge	\$0.8100	Per Mcf/Mo.
Commodity Charge	5.1191	Per Mcf

Base Rate Calculation

Firm

Demand 1/	\$0.0658	Per Mcf
Commodity	5.1191	Per Mcf
Total Firm Base Cost	<u>\$5.1849</u>	Per Mcf

Interruptible:

Commodity	\$5.1191	Per Mcf
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1/ Demand base rate calculation: $4,768 \times 12 \times \$0.8100 / 707,222$

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twelfth Revised Sheet No. 5
Superseding
Eleventh Revised Sheet No. 5

STATEMENT OF RATES (Rates Per Dekatherm)	
Currently Effective Term-Differentiated Rates	
Rate Schedule	Base Tariff Rate
=====	
Category 1 (Contract Term of less than 3 Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.7671
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.8871
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$2.1400
Zone 2 - 2 Minimum Rate	\$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.6171
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.7371
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$1.9900
Zone 2 - 2 Minimum Rate	\$0.0000
Category 3 (Contract Term of 5 or more Years)	

Monthly Reservation Rates	
FT-A	
Zone 1 - 1 Maximum Rate	\$3.4671
Zone 1 - 1 Minimum Rate	\$0.0000
Zone 1 - 2 Maximum Rate	\$4.5871
Zone 1 - 2 Minimum Rate	\$0.0000
Zone 2 - 2 Maximum Rate	\$1.8400
Zone 2 - 2 Minimum Rate	\$0.0000

Issued by: Raymond D. Neppl, Vice President

Issued on: November 29, 2005

Effective on: January 1, 2006

Filed to comply with order of the Federal Energy Regulatory Commission, Docket
No. RP02-132-002, issued November 8, 2002, 01 FERC ¶ 61,170

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Twenty-Seventh Revised Sheet No. 5B
Superseding
Twenty-Sixth Revised Sheet No. 5B

STATEMENT OF RATES (Rates Per Dekatherm)				
Rate Schedule -----	Base Tariff Rate -----	Adjustment Under Section 19 1/ -----	Rate After Current Adjustment -----	Fuel and Loss Retention Percentages 2/ -----
Commodity Rates				
FT-A - Maximum Rates				
Zone 1 - 1	\$0.0130	\$0.0019	\$0.0149	0.74%
Zone 1 - 2	\$0.0130	\$0.0019	\$0.0149	0.87%
Zone 2 - 2	\$0.0130	\$0.0019	\$0.0149	0.13%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	
IT and AOT				
Zone 1 - 1	\$0.1368	\$0.0019	\$0.1387	0.74%
Zone 1 - 2	\$0.1737	\$0.0019	\$0.1756	0.87%
Zone 2 - 2	\$0.0834	\$0.0019	\$0.0853	0.13%
Minimum Rate	\$0.0130	\$0.0019	\$0.0149	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of \$0.0019 per Dekatherm shall be added to other charges under Company's Rate Schedules.

2/ Fuel and Losses Retention Percentages shall be applicable to all transportation rate schedules.

Transportation Fuel and Loss Retention Percentages are inclusive of the following percentages for Gas Lost and Unaccounted For: .05% for Zone 1-1, .06% for Zone 1-2, and .01% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted For percentages.

Issued by: Ron Mucci, Vice President of Regulatory
Issued on: September 23, 2009

Effective on: November 1, 2009

Viking Gas Transmission Company
FERC Gas Tariff
First Revised Volume No. 1

Fourteenth Revised Sheet No. 5C
Superseding
Thirteenth Revised Sheet No. 5C

STATEMENT OF RATES
(Rates Per Dekatherm)

Rate Schedule -----	Base Tariff Rate -----	Adjustment Under Section 27 1/ -----	Rate After Current Adjustment -----
LMS - Monthly Demand Rate	\$1.0000		\$1.0000
LMS - Daily Overrun Rate	\$0.1737		\$0.1737
LMS - Load Management Cost Reconciliation Adjustment		\$0.0080	

1/ Pursuant to Section 27 of the General Terms and Conditions of this Tariff, a mechanism is established to reconcile through surcharges or credits to the Rate Schedule LMS rate, as appropriate, differences between the cost to maintain Company's line pack gas and the amounts Company receives or pays for such gas arising out of the purchase and sale of such gas.

Issued by: J. Phill May, Vice President Commercial
Issued on: February 20, 2009

Effective on: April 1, 2009

R A T E S C H E D U L E T F

RESERVATION RATES	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
	TF12 Base	TF12 Variable	TF5	TFF
Base Tariff Rates 1/				
Summer (Apr-Oct)	5.683	5.683	-0-	5.473
Winter (Nov-Mar)	10.230	13.866	15.153	9.853

COMMODITY RATES 2/		Market Area 3/		Field Mileage 5/		Carlton Surcharge 4/		Out-of Balance 3/	
TF12 Base, TF12 Var., TF5 & TFF		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Receipt Point	Delivery Point								
Market	Market	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 where applicable.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where Applicable, Field Area Electric Compression charge of \$0.0000 and ACA will be added to the mileage based rates.

R A T E S C H E D U L E S T F X a n d L F T

RESERVATION RATES		MARKET-TO-MARKET		FIELD-TO-FIELD			
		Apr-Oct	Nov-Mar	Apr-Oct		Nov-Mar	
Base Tariff Rates 1/		\$5.683	\$15.153	\$5.473	\$9.853		

COMMODITY RATES 2/ TFX and LFT		Market Area 3/		Field Mileage 5/ Rate per 100 miles		Carlton Surcharge 4/		Out-of-Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0381	0.0212			0.0175	0.0000	0.0381	0.0212
Field	Market	0.0381	0.0212	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0295	0.0109

GULF COAST		Reservation 1/		Commodity 6/		Out-of-Balance 6/	
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
MOPS Gathering		1.0514	0.0000	0.0019	0.0019	0.0019	0.0019
MOPS Transmission		1.5337	0.0000	0.0019	0.0019	0.0019	0.0019
Tivoli - Downstream		0.6827	0.0000	0.0019	0.0019	0.0019	0.0019
Other Gulf Coast		4.8169	0.0000	0.0019	0.0019	0.0019	0.0019

- 1/ The minimum reservation rate is equal to zero.
- 2/ The applicable Mileage Indicator Districts (MIDs) billing rate will be added to the TF rates for volumes received in the Field Area, or received in the Market Area and delivered to the Field Area. The MIDs rates shown on Sheet Nos. 59-60A represent the total maximum Field Area throughput commodity rates for any transaction involving MIDs.
- 3/ Maximum and Minimum rates include ACA of \$0.0019 and the Market Area Electric Compression charge of \$0.0003 where applicable.
- 4/ Applicable to Market Area shippers as provided for in the Carlton Settlement filed in Docket No. RP96-347 dated October 28, 1996.
- 5/ Where applicable, Field Area Compression charge of \$0.0000 and ACA will be added to the mileage based rates.
- 6/ Maximum and Minimum rates include ACA of \$0.0019.

**Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
January 2010**

The principal gas sources of natural gas for Wahpeton, North Dakota are from the large Western Canadian Sedimentary Basin (WCSB). The pricing point for much of this gas is the Alberta Energy Company (AECO-C), one of the largest and most liquid volume points in North America. The January monthly price for the AECO Index is expected to increase from the previous month index. The AECO Index is based on the weighted average one month spot price at AECO-C and Nova Inventory Transfer (N.I.T.) as reported by Natural Gas Exchange (NGX).

The major factor contributing to the price increase was below normal temperatures across much of the nation during the month of December resulting in high demand for space heating and subsequent large withdrawals from storage. The Energy Information Administration (EIA) reported storage levels nationwide as of December 18, 2009 were 13.1 percent above the five-year average and 11.8 percent above last year's balance.

The Department of Energy's (DOE) Energy Information Administration (EIA) provides various publications on energy issues. The information is available on the DOE website: <http://www.eia.doe.gov>.

The most recent Short-Term Energy Outlook specific to natural gas prices, supply and demand is provided as pages 2 through 12.



December 2009

Short-Term Energy Outlook

December 8, 2009 Release

Highlights

- EIA expects the price of West Texas Intermediate (WTI) crude oil will average about \$76 per barrel this winter (October-March). The forecast for the monthly average WTI price dips to \$75 early next year then rises to \$82 per barrel by December 2010, assuming U.S. and world economic conditions continue to improve. EIA's forecast assumes that U.S. real gross domestic product (GDP) grows by 1.9 percent in 2010 and world oil-consumption-weighted real GDP grows by 2.6 percent.
- Rising crude oil prices contribute to an increase in the annual average regular-grade gasoline retail price from \$2.35 per gallon in 2009 to \$2.83 in 2010, as pump prices approach \$3 per gallon during next year's driving season. Projected annual average diesel fuel retail prices are \$2.46 and \$2.96 per gallon, respectively, in 2009 and 2010. Average household expenditures on heating oil this winter are expected to increase to \$1,911 from \$1,864 last winter. Projected average household expenditures for propane of \$1,700 this winter are almost 13 percent lower than last winter's \$1,950.
- EIA expects the annual average natural gas Henry Hub spot price for 2010 to be \$4.62 per thousand cubic feet (Mcf). This represents a \$0.67-per-Mcf increase from the estimated 2009 price of \$3.95 per Mcf. Natural gas working inventories reached a new record-high level of 3.837 trillion cubic feet (Tcf) on November 27 as mild weather throughout much of the country contributed to uncommon storage builds for most of that month. Projected average household expenditures on natural gas total \$778 this winter, compared with \$889 last winter.

Global Crude Oil and Liquid Fuels

Global Petroleum Overview. As 2009 draws to a close and the Organization of the Petroleum Exporting Countries (OPEC) prepares to meet again at the end of the month, it faces a global oil market that has firmed up in response to production cuts that began to take effect in January 2009. Although OPEC compliance with the cuts has weakened and global oil inventories remain very high by historical standards, WTI oil prices averaged \$78 per barrel in November, continuing their generally upward trend since February. Expectations of a continued global economic turnaround have buttressed oil markets, and this *Outlook* assumes world oil-consumption-weighted real GDP grows by 2.6 percent in 2010, following a decline of 0.7 percent in 2009. EIA's expectation is that OPEC crude oil output in 2010 will hold at roughly fourth-quarter 2009 levels of under 30 million barrels per day.

Global Petroleum Consumption. EIA forecasts that world oil consumption will grow in 2010 by 1.1 million barrels per day (bbl/d) to 85.2 million bbl/d ([World Liquid Fuels Consumption Chart](#)), down slightly from last month's *Outlook*. Countries outside of the Organization for Economic Cooperation and Development (OECD) are likely to account for almost all of this growth. Projected OECD oil consumption grows by only 0.1 million bbl/d in 2010, despite a projected 0.27 million bbl/d increase in the United States after a very weak 2009.

Non-OPEC Supply. EIA expects non-OPEC oil production to average 50.3 million bbl/d in 2009, about 0.6 million bbl/d higher than year-earlier levels. Non-OPEC oil production increases have been largely the result of higher production from the United States, Brazil, and the Former Soviet Union (FSU). Oil production in Colombia has also been surprisingly strong. According to preliminary data, the country's crude oil output exceeded 0.7 million bbl/d in October for the first time since 2000. Projected non-OPEC supply growth slows to 0.2 million bbl/d in 2010, largely the result of lower growth in the United States and FSU ([Non-OPEC Crude Oil and Liquid Fuels Production Growth Chart](#)).

OPEC Supply. OPEC crude oil production is expected to average 29.1 million bbl/d in 2009, down more than 2 million bbl/d from year-earlier levels. Projected OPEC crude oil production increases to an average of 29.6 million bbl/d in 2010, a response to an anticipated rebound in global oil demand ([World Crude Oil and Liquid Fuels Production Growth Chart](#)). EIA expects OPEC non-crude petroleum liquids, which are not subject to OPEC production targets, to grow by 0.6 million bbl/d in 2010. OPEC is scheduled to meet in Angola on December 22 to reassess the market situation. Through the forecast period, OPEC surplus crude oil production capacity

should remain in excess of 4 million bbl/d, versus an average of 2.8 million bbl/d seen over the 1998-2008 period ([OPEC Surplus Crude Oil Production Capacity Chart](#)).

OECD Petroleum Inventories. OECD commercial oil inventories stood at 2.77 billion barrels at the end of the third quarter of 2009, 115 million barrels more than the 5-year average. Inventories are projected to be at 58 days of forward cover at the end of 2009, 5 days above the 5-year average for that time of year ([Days of Supply of OECD Commercial Stocks Chart](#)). EIA expects OECD oil inventories to remain above average historical levels throughout the forecast period.

Crude Oil Prices. WTI crude oil spot prices averaged \$78 per barrel in November, more than \$2 per barrel above than the prior month's average. This increase reflected improving expectations of a global economic recovery and higher oil consumption offsetting concerns about the high current level of oil inventories. EIA forecasts that WTI spot prices will weaken over the next few months, falling to about \$75 per barrel in February, and then rising to about \$82 per barrel by the end of next year ([West Texas Intermediate \(WTI\) Crude Oil Price Chart](#)).

Crude oil prices were less volatile in November than during October. During November, the WTI spot price traded within a \$5-per-barrel range, between roughly \$75 and \$80 per barrel. This contrasts with October, when the WTI spot price averaged just under \$76 per barrel and traded in an \$11-per-barrel range, between roughly \$70 and \$81 per barrel.

In the crude oil futures options market, WTI implied volatility trended lower over the second half of October and most of November 2009, following the downtrend in spot price volatility. Implied volatility from the February 2010 futures options contracts averaged 40 percent for the 5 days ending December 3, with the lower and upper limits of the 95-percent confidence interval for the February 2010 futures price at about \$60 per barrel and \$112 per barrel respectively (see [Energy Price Volatility and Forecast Uncertainty](#)). The February 2010 WTI futures contract averaged \$78.43 per barrel for the 5 days ending December 3.

Last year at this time, market participants were pricing WTI crude oil in February 2009 at \$50 per barrel, about \$28 below the level currently trading for February 2010 delivery. The implied volatility last year for the February 2009 contract was double the current level, at 82 percent per year, with lower and upper limits of \$29 and \$84 per barrel, respectively, for the 95-percent confidence interval. The higher implied volatility reflected continued market uncertainty following a price collapse from all-time highs for the WTI futures of more than \$145 per barrel in July 2008.

U.S. Crude Oil and Liquid Fuels

U.S. Petroleum Consumption. Total consumption of liquid fuels and other petroleum products is projected to average 18.7 million bbl/d, or about 800,000 bbl/d (4.1 percent) lower in 2009 compared with 2008 ([U.S. Liquid Fuels Consumption Growth Chart](#)). During the first half of 2009, total consumption fell by almost 1.25 million bbl/d (6.3 percent) from the same period last year, one of the steepest declines on record. The year-over-year projected decline in petroleum consumption slowed to 280,000 bbl/d (1.5 percent) in the third quarter 2009, although this is in large part due to a 220,000-bbl/d increase in motor gasoline consumption as high prices and Hurricanes Gustav and Ike depressed gasoline consumption last year. Year-over-year total petroleum consumption is 430,000 bbl/d (2.2 percent) lower in the fourth quarter of 2009 as the gains in gasoline consumption return to near zero and warmer weather in the eastern United States reduces heating fuel demand. The modest economic recovery assumed for 2010 partly contributes to an increase in total liquid fuels consumption of 270,000 bbl/d (1.4 percent).

U.S. Petroleum Supply. EIA expects U.S. crude oil production will average 5.34 million bbl/d in 2009, the first production increase since 1991. Production is forecast to increase to an average of 5.44 million bbl/d in 2010 ([U.S. Crude Oil Production Chart](#)). The growth in production comes primarily from the Federal Offshore Gulf of Mexico. Crude oil production from the Thunder Horse, Tahiti, Shenzi, and Atlantis Federal offshore fields is expected to account for 12 percent of total U.S. crude oil production by the fourth quarter of 2010.

U.S. Petroleum Product Prices. Regular grade motor gasoline prices are expected to average \$2.65 per gallon in December, unchanged from the November average but almost \$1 per gallon higher than last December. In 2010 the refiner cost for crude oil averages about \$77 per barrel, or over \$17 per barrel (41 cents per gallon) higher than the 2009 average, contributing to an expected \$0.48-per-gallon increase in regular-grade gasoline prices to an average of \$2.83 per gallon next year. Diesel fuel retail prices, which averaged \$2.79 per gallon in November, are expected to average \$2.96 per gallon in 2010. Residential heating oil prices this winter (October through March) are projected to average \$2.77 per gallon, compared with \$2.63 per gallon last winter.

Natural Gas

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will decrease by 1.9 percent in 2009 and by an additional 0.4 percent in 2010 ([Total U.S. Natural Gas Consumption Growth Chart](#)). A steep decline in demand by the industrial sector, and smaller but significant declines in the residential and

commercial sectors, have been partially offset by consumption growth in the electric power sector this year. Low natural gas prices relative to coal caused substantial switching to natural gas for baseload electric power generation throughout most of 2009. However, in recent weeks, natural-gas-fired generation has been closer to year-ago levels because of the seasonal increase in natural gas prices and the decrease in coal prices driven by historically high coal stocks. In addition, warmer-than-normal weather over the eastern United States during November depressed seasonal space-heating demand in the residential and commercial sectors. This weaker consumption is evident in natural gas working inventories, which increased by an estimated 9 billion cubic feet (Bcf) during November compared with the previous 5-year average decline of about 57 Bcf over the month.

A return to normal weather and expectations for economic growth are the primary drivers in EIA's forecast for consumption increases in the residential, commercial, and industrial sectors in 2010. However, EIA still expects total consumption to fall as higher natural gas prices contribute to some reversal of the coal-to-natural-gas switching that took place in the electric power sector during 2009.

U.S. Natural Gas Production and Imports. EIA expects total marketed natural gas production will increase by 3.7 percent in 2009, followed by a decline of 3.1 percent in 2010. Minimal hurricane disruptions and significant growth in production from onshore shale basins have contributed to the increase in domestic supply this year, despite a nearly 60-percent decline in the working natural gas rig count from September 2008 to July 2009. According to Baker Hughes, the working natural gas rig count is currently 748, up 83 from the low of 665 this past July. Although marketed production in the Lower-48 non-Federal Gulf of Mexico has declined since peaking in February 2009, the recent dip in September production appears to be the result of shut-ins, maintenance, and pipeline constraints, as opposed to declining field productivity. Production volumes are expected to have recovered in October and November. Shorter completion times and enhanced well productivity in shale basins contributed to sustained higher production levels amidst a dramatically lower rig count in 2009.

U.S. pipeline imports averaged about 9 Bcf/d through the first 9 months of 2009, compared with 9.9 Bcf/d during the same period last year. Lower drilling activity and natural gas production in Canada have contributed to reduced pipeline import flows this year. EIA expects pipeline imports to fall by 12 percent for the year. The persistence of low rig counts in Canada leads to lower expected Canadian natural gas production and lower U.S. pipeline imports next year. Offsetting a portion of the decline in pipeline imports, U.S. liquefied natural gas (LNG) imports increased in 2009, averaging about 1.3 Bcf/d through September compared with almost 1.0 Bcf/d

during the same period last year. Imports rose, albeit from very low levels in 2008, as new global liquefaction capacity added to supply while global LNG demand suffered under the economic crisis. EIA expects that U.S. LNG imports will increase to 1.7 Bcf/d in 2010 with the expected completion of additional global LNG supply projects, although the start-up dates for supply additions have historically been subject to delay.

U.S. Natural Gas Inventories. On November 27, 2009, working natural gas in storage was 3,837 Bcf ([U.S. Working Natural Gas in Storage Chart](#)), 487 Bcf above the 5-year average (2004–2008) and 470 Bcf above the level during the corresponding week last year. Assuming a storage withdrawal between the end of November and the end of March about 6.1 percent (113 Bcf) greater than the previous 5-year average for that period, end-of-winter (March 31, 2010) stocks will be about 1,845 Bcf. This would be the highest end-of-winter storage level since 1991, when inventories measured 1,912 Bcf.

U.S. Natural Gas Prices. The Henry Hub spot price averaged \$3.77 per Mcf in November, \$0.35 per Mcf lower than the average spot price in October ([Henry Hub Natural Gas Price Chart](#)). Prices were depressed as warmer-than-normal weather in November reduced seasonal residential and commercial space-heating consumption by about 1.7 Bcf/d, or about 7 percent, below the projected 22.85 Bcf/d consumption in last month's *Outlook*. EIA expects prices to increase as space-heating demand rises in the coming months. However, strong domestic production, a retrenchment of electric-power-sector natural gas demand, and uncertainty about the extent of recovery in the industrial sector, should limit sustained upward price movements through the winter and well into next year. The projected Henry Hub spot price averages \$3.95 per Mcf in 2009 and \$4.62 per Mcf in 2010.

Market participants were pricing gas delivered to Henry Hub in January 2010 through futures contracts at \$4.76 per million Btu (MMBtu) (\$4.90 per Mcf) during the 5 days ended December 3. Implied price volatility for the January 2010 natural gas futures contract averaged just over 56 percent (see [Energy Price Volatility and Forecast Uncertainty](#)). This translates into a 95-percent confidence interval with a lower limit of \$3.60 and an upper limit of approximately \$6.30 per MMBtu for the January 2010 contract. The implied price volatility reflects market participants' uncertainty over how production, demand, and high inventories will be balanced in the upcoming winter heating season.

At this time last year, natural gas for delivery in January 2009 to the Henry Hub was trading at \$6.38 per MMBtu, and the implied volatility was almost 68 percent. This

translated into a lower and upper limit of \$4.65 and \$8.75 per MMBtu, respectively, for the 95-percent confidence interval.

Electricity

U.S. Electricity Consumption. Retail sales of electricity to the industrial sector from January through September 2009 were down by about 12 percent compared with the same period last year, similar to the decline in the U.S. manufacturing production index. EIA's assumption of 3.6 percent growth in manufacturing during 2010 translates to an expected growth in electricity sales to the industrial sector of about 1.1 percent. EIA forecasts electricity sales to the residential and commercial sectors to increase by 2.4 percent and 1.2 percent, respectively, in 2010 with total electricity consumption increasing by 1.6 percent ([U.S. Total Electricity Consumption Chart](#)).

U.S. Electricity Generation. The projected share of electricity generated by natural gas in the electric power sector falls from 22 percent in 2009 to 21 percent next year. This reduction will be offset by expected increases in generation from coal-fired plants, as a result of switching away from higher-priced natural gas generation and from renewable sources, especially as a result of increased windpower capacity.

U.S. Electricity Retail Prices. EIA expects delivered natural gas fuel costs for generating electricity to rise by 10 percent next year. However, lower delivered coal costs combined with comparatively more generation from coal should reduce residential electricity prices by about 0.9 percent next year ([U.S. Residential Electricity Prices Chart](#)).

Coal

U.S. Coal Consumption. Coal consumption by the electric power sector fell nearly 12 percent for the first 9 months of 2009 in response to lower total electricity generation coupled with increases in generation from other sources, natural gas, hydropower, and wind. An expected continuation of these trends for the rest of the year leads to an annual decline in electric-power-sector coal consumption of almost 10 percent. Projected increases in electricity demand and higher natural gas prices will contribute to growth in coal-fired generation in 2010. Forecast coal consumption in the electric power sector increases by nearly 4 percent in 2010 but remains below 1 billion short tons for the second consecutive year. Coal consumed for coke production declined by 30 percent in the first half of 2009 compared with the first half of 2008. Consumption of coal at coke plants rises in 2010 as economic conditions improve, with an increase of more than 3 million short tons (21 percent). EIA projects 3-percent growth in 2010

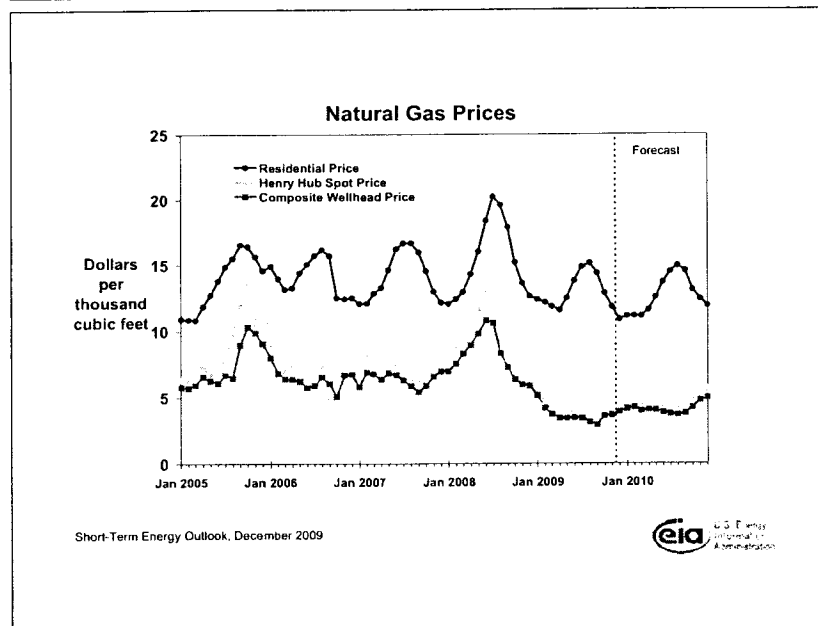
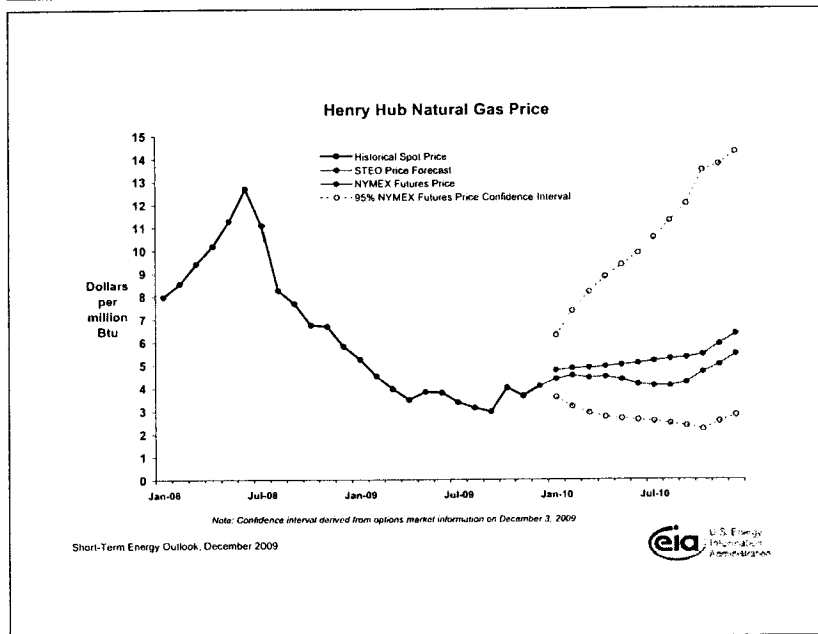
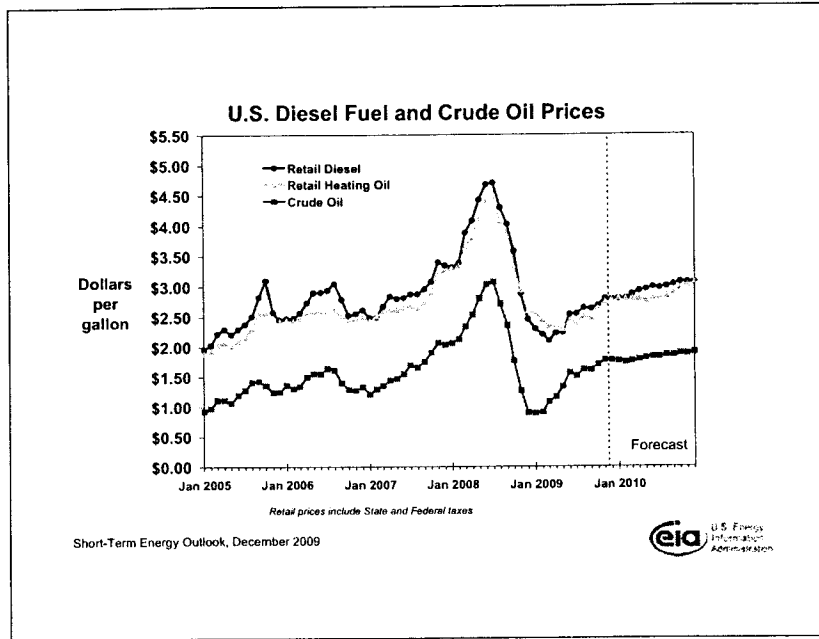
for coal consumption in the retail and general industry sectors, following a 17-percent decline in 2009 ([U.S. Coal Consumption Growth Chart](#)).

U.S. Coal Supply. Coal production for the first 3 quarters of 2009 fell by 6 percent in response to lower U.S. coal consumption, fewer exports, and higher coal inventories. These conditions are expected to persist for the remainder of 2009, with an annual decline in coal production of nearly 7 percent. Production declines by an additional 2.5 percent in 2010 in this forecast despite increases in domestic consumption and exports. Balance is maintained through a reduction in coal inventories and increased imports ([U.S. Annual Coal Production Chart](#)).

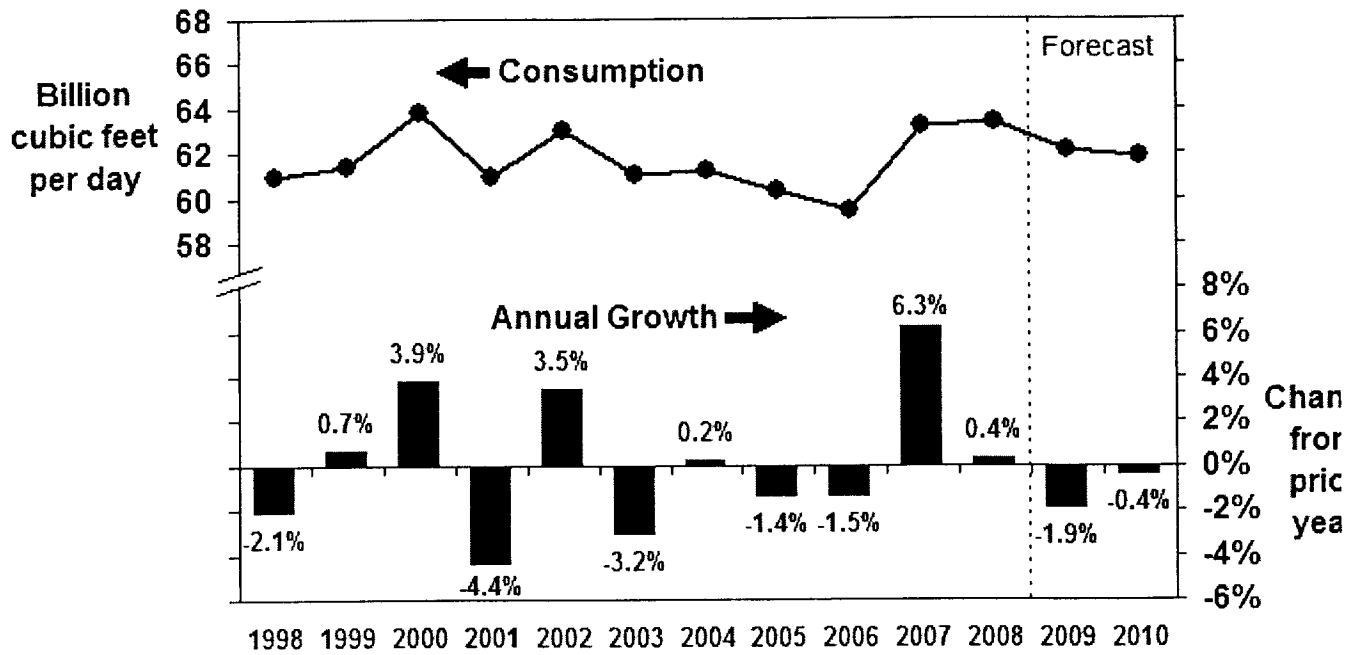
U.S. Coal Prices. Despite decreases in spot coal prices, lower prices for other fossil fuels, and declines in demand for coal for electricity generation, EIA expects the delivered electric-power-sector coal price to average about \$2.22 per MMBtu for 2009, a 7-percent increase. This higher cost of delivered coal is due to the significant portion of power-sector coal contracts initiated during a period of high prices for all fuels. The projected electric-power-sector delivered coal price falls by 8 percent to average \$2.03 per MMBtu in 2010.

U.S. Carbon Dioxide Emissions

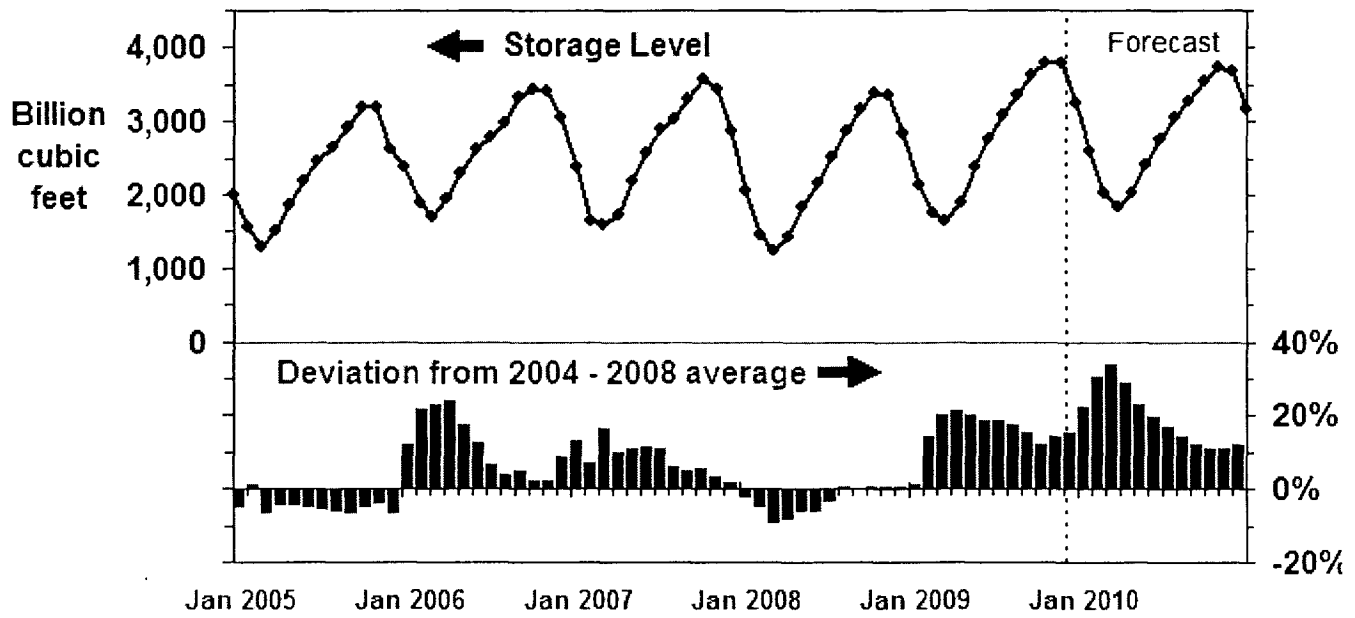
Projected carbon dioxide (CO₂) emissions from fossil fuels fall by an estimated 6.1 percent in 2009. Emissions from coal leads the drop in 2009 CO₂ emissions, falling by more than 10 percent. Changes in energy consumption in the industrial sector, a result of the weak economy, and changes in electricity generation sources are the primary reasons for the decline in CO₂ emissions ([U.S. Carbon Dioxide Emissions Growth Chart](#)). Projected improvements in the economy contribute to an expected 1.5-percent increase in CO₂ emissions in 2010.



U.S. Total Natural Gas Consumption



U.S. Working Natural Gas in Storage



NOTE: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2004 - Dec. 2008

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
FIRM**

	(Over) Under Recovery	Refunds & Other	Interest 1/ 2/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2009									\$65,941
May	(\$2,105)	\$0	\$671	(\$1,434)	16,822	(\$0.1857)	(\$3,124)	\$1,690	67,631
June	24,415	0	690	25,105	9,107	0.2343	(427) 2/	25,532	93,163
July	39,344	0	629	39,973	6,447	0.2343	1,511	38,462	131,625
August	39,771	0	902	40,673	5,943	0.2343	1,392	39,281	170,906
September	(2,165)	0	1,179	(986)	5,775	0.2343	1,353	(2,339)	168,567
October	35,022	0	1,154	36,176	11,535	0.2343	2,703	33,473	202,040
November	(980)	0	1,387	407	19,033	0.2343	4,459	(4,052)	197,988
Balance @ November 30, 2009.									\$197,988

1/ Interest calculated at 13.3%, the authorized rate of return.

2/ Reflects 6,097.5 dk @ (\$0.1857) and 3,009.9 dk @ \$0.2343.

**GREAT PLAINS NATURAL GAS CO.
COMPUTATION OF (OVER) / UNDER RECOVERED GAS COST ACCOUNT BALANCE
APPLICABLE TO NORTH DAKOTA
INTERRUPTIBLE**

	(Over) Under Recovery	Refunds & Other	Interest 1/ 2/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change- Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2009									(\$110,191)
May	(\$5,411)	\$0	(\$1,024)	(\$6,435)	15,426	(\$0.7309)	(\$11,275)	\$4,840	(105,351)
June	(2,099)	0	(967)	(3,066)	10,879	(0.7419)	(7,985) 2/	4,919	(100,432)
July	(3,038)	0	(592)	(3,630)	7,435	(0.7419)	(5,516)	1,886	(98,546)
August	(4,584)	0	(581)	(5,165)	9,775	(0.7419)	(7,252)	2,087	(96,459)
September	(14,605)	0	(571)	(15,176)	9,230	(0.7419)	(6,848)	(8,328)	(104,787)
October	(9,999)	0	(634)	(10,633)	16,552	(0.7419)	(12,280)	1,647	(103,140)
November	(15,225)	0	(633)	(15,858)	18,004	(0.7419)	(13,357)	(2,501)	(105,641)
Balance @ November 30, 2009.									(\$105,641)

1/ Interest calculated at 13.3%, the authorized rate of return.

2/ Reflects 7,849.5 dk @ (\$0.7309) and 3,029.9 dk @ (\$0.7419).