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

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April 30, 2014

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

Re: Cost of Gas Adjustment (COG)
May 2014

Great Plains Natural Gas Co. (Great Plains), a Division of MDU Resources Group, Inc., herewith submits an original and two (2) copies of a Cost of Gas Adjustment (COG) pursuant to North Dakota Century Code 49-05-05.

Attachment A is the Rate Summary Sheet (98th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (98th Revised Sheet No. 8), showing the May 2014 cost of gas and the resulting Cost of Gas Adjustment. The tariff sheets also reflect the Commission's approval for billing on a Dk basis effective with service provided on and after May 6, 2014 in Case No. PU-13-551.

Attachment B shows the calculations supporting the gas costs for May 2014, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.1020 per Dk for residential and firm general service customers and has decreased $0.1022 per Dk for large and small interruptible customers since the last COG filing. There has been a decrease in pipeline charges of $0.0072 per Dk due to a change in the three year normalized Dk sales volumes. The net effect of these changes is a decrease of $0.1092 per Dk 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, 2013.

Great Plains submitted a check for $600.00 on January 2, 2014 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,

Tamie A. Aberle
Director of Regulatory Affairs

Attachments

Attachment A

GREAT PLAINS NATURAL GAS CO.

A Division of MDU Resources Group, Inc.

State of North Dakota
Gas Rate Schedule

NDPSC Volume 2
98th Revised Sheet No. 1.1
Canceling 97th Revised Sheet No.1.1
Page 1 of 1

RATE SUMMARY SHEET

Rate Schedule	Sheet No.	Basic Service Charge	Distribution Delivery Charge		COG Items	Total Rate/dk
Firm Gas Service - General	2	$3.50 per month	First 10 dk	$1.2869	$7.2421	$8.5290
			Over 10 dk	1.0646		8.3067
Interruptible Gas Service - General	3	$3.50 per month	First 400 dk	$1.1506	$4.8114	$5.9620
			Next 2,600 dk	0.9021		5.7135
			Over 3,000 dk	0.7486		5.5600
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All dk	$1.2516	$4.8114	$6.0630
Transportation Service	5	$3.50 per month	First 400 dk	$1.1506		$1.1506
			Next 2,600 dk	0.9021		0.9021
			Over 3,000 dk	0.7486		0.7486

Date Filed: April 30, 2014

Effective Date: Service rendered on and after May 6, 2014

Issued By: Tamie A. Aberle
Director - 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
98th Revised Sheet No. 8
Canceling 97th Revised Sheet No. 8

COST OF GAS

Summary:	Firm				Interruptible		
	Est. Wtd. Demand Costs	Average Commodity	GCR Adj.	Est. Wtd. Total Firm	Average Commodity	GCR Adj.	Total Int.
Base Rate	$0.0662	$5.1708	$0.0000	$5.2370	$5.1708	$0.0000	$5.1708
Accumulated Adj.	1.4522	(0.2993)	0.9614	2.1143	(0.2846)	0.0274	(0.2572)
Current Adj.	(0.0072)	(0.1020)	0.0000	(0.1092)	(0.1022)	0.0000	(0.1022)
Total Adj.	1.4450	(0.4013)	0.9614	2.0051	(0.3868)	0.0274	(0.3594)
Total Rate	$1.5112	$4.7695	$0.9614	$7.2421	$4.7840	$0.0274	$4.8114

Date Filed: April 30, 2014

Effective Date: Service rendered on and after May 6, 2014

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2014

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A - Zone 1-1	8,000		$3.3978	12	$326,189	$0.2315
FT-A - Zone 1-1	5,000		3.6918	5	92,295	0.0655
FT-A Seasonal	2,000		3.6918	5	36,918	0.0262
TFX Seasonal	2,000		15.1530	5	151,530	0.1075
TFX - Winter	13,000		15.1530	5	984,945	0.6990
TFX - Summer	13,000		5.6830	7	517,153	0.3670
LMS Demand 2/						0.0145
Total Demand Charges					$2,109,030	1.5112
Estimated Weighted Average Commodity Cost	1,409,081	1/	4.7695		6,720,612	4.7695
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$8,829,642	7.2421
Base Cost of Gas						5.2370
Accumulated Adjustment						$2.0051

Interruptible	
Estimated Weighted Average Commodity Cost	$4.7695
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0145
Total Current Interruptible Gas Cost	4.8114
Base Cost of Gas	5.1708
Accumulated Adjustment	($0.3594)

1/ Three year normalized average Dk sales
2/ Amount divided by 2011-2013 average normalized interruptible sales volumes plus 2011-2013 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$0.9800	12	$29,400	$0.0145

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
MAY 2014

Rates Effective May 1, 2014	$/Dk	
FT-A - Zone 1-1 (Category 1)	$3.6918	Per Dk/Mo.
FT-A - Zone 1-1 (Category 3)	3.3978	Per Dk/Mo.
FT-A - Seasonal	3.6918	Per Dk/Mo.
TFX	15.1530	Per Dk/Mo.
TFX Seasonal	15.1530	Per Dk/Mo.
LMS Demand	0.9800	Per Dk/Mo.
Estimated Weighted Average Commodity Cost:	4.7695	Per Dk

Base Rate Effective September 1, 1981 1/		
Demand Charge	$0.8100	Per MCF/Mo.
Commodity Charge	5.1191	Per MCF

Base Rate Calculation

Firm		
Demand 2/	$0.0662	Per Dk
Commodity	5.1708	Per Dk
Total Firm Base Cost	$5.2370	Per Dk
Interruptible:		
Commodity	$5.1708	Per Dk

1/ The Firm Gas Base Cost is based on the FERC Gas Tariff, Third Revised Volume No. 1 of Midwestern Gas Transmission Company, effective July 1, 1981.

2/ Demand base rate calculation:

Demand Charge		0.81	Per MCF/Mo.
Convert mcf to dk	x	0.99	Therm Factor
		0.82	Per Dk/Mo.
Capacity	x	4,768	
Months	x	12	
		46,814.13	
Volumes	/	707,222	
		0.0662	Per Dk

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

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	$3.6918
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.7894
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$2.0972
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	$3.5448
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.6424
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.9502
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	$3.3978
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$4.4954
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$1.8032
Zone 2-2 Minimum Rate	$0.0000

Rate Schedule	Base Tariff Rate	Fuel and Loss Retention Percentages 2/
Commodity Rates 1/		
FT-A – Maximum Rates		
Zone 1-1	$0.0127	0.08%
Zone 1-2	$0.0127	0.10%
Zone 2-2	$0.0127	0.02%
Minimum Rate	$0.0127	
IT and AOT		
Zone 1-1	$0.1341	0.08%
Zone 1-2	$0.1702	0.10%
Zone 2-2	$0.0816	0.02%
Minimum Rate	$0.0127	

1/ Pursuant to Section 19 of the General Terms and Conditions, the maximum and minimum commodity rates shall be increased to include the Commission-authorized Annual Charge Adjustment unit rate as published on the Commission's Web Site located at http://www.ferc.gov.

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: 0.01% for Zone 1-1, 0.01% for Zone 1-2, and 0.00% for Zone 2-2. Transportation entirely by backhaul will incur only the Gas Lost and Unaccounted for percentages.

Rate Schedule	Base Tariff Rate	Adjustment Under Section 27 1/	Rate After Current Adjustment
LMS – Monthly Demand Rate	$0.9800		$0.9800
LMS – Daily Overrun Rate	$0.1702		$0.1702
LMS – Load Management Cost Reconciliation Adjustment		$0.0116	

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.

Rate Schedule	Maximum Rate Per Dekatherm	Minimum Rate Per Dekatherm
PAL		
NPL, OPL, and APL Service:		
Daily Commodity Rate	$0.1702	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1702	$0.0000

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
RESERVATION RATES	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/ TF12 Base, TF12 Var., TF5 & TFF		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	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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 maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Electric Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.

RATE SCHEDULES TFX and LFT

	MARKET-TO-MARKET		FIELD-TO-FIELD	
RESERVATION RATES	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	0.0364	0.0195			0.0175	0.0000	0.0364	0.0195
Field	Market	0.0364	0.0195	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0276	0.0090

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

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 maximum Field Area throughput commodity rates for any transaction involving MIDs. For volumes transported through Northern's Ft. Buford compressor station, the commodity rate, fuel and unaccounted for apply only to volumes that are not ultimately confirmed for re-delivery into Northern's Market Area.
3/ The Maximum and Minimum rates include the Market Area Electric Compression charge of $0.0005 where applicable. In addition, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.
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, the Field Area Compression charge of $0.0000 and the ACA unit surcharge as set forth on FERC's website at http://www.ferc.gov will be added to the mileage based rates.
6/ In addition to the Maximum and Minimum rates, Shipper shall pay the ACA unit surcharge as posted on FERC's website at http://www.ferc.gov.

RATE SCHEDULES TF, TFX, LFT, GST, TI, & FDD

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.09% 4/ 5/
FDD Storage Fuel	1.76%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0005
Field Area	$0.0000

1/ Northern will adjust its Fuel percentages and electric compression commodity rates in accordance with Sections 53A and 53B, respectively, of the General Terms and Conditions of this Tariff.

2/ Fuel shall be determined by Mileage Indicator Districts (MIDS) for the Field Area.

3/ Fuel charged in the Field and Market Areas for a pooling transaction or for processing plant transactions will not exceed the fuel charged on a unified Field-to-Market transaction having the same initial Field receipt point and ultimate Market delivery point, i.e., the total fuel collected for transactions that go into and out of pooling points or processing plants in either the Field Area or the Market Area will be no greater than the fuel collected on the total path between the original receipt point and the ultimate delivery point, subject to the shipper(s) providing Northern the requisite information.

4/ The Unaccounted For percentage utilizes the most recent twelve-month period ending December 31, 2013.

5/ Sheet No. 54A identifies the specific transportation transactions exempt from fuel and unaccounted-for retention charges.

6/ The Out-of-Balance Fuel Percentage for deliveries in MIDS 1-7 shall be the applicable Section 1 Mainline Fuel percentage, and for deliveries in MIDS 8-16B shall be the applicable Section 2 Mainline Fuel percentage.

In the event facilities have been abandoned, Northern shall have the right to file to reduce the applicable MID fuel percentage(s) on a common basis for all transactions affected by the abandonment to reflect the reduction in use for the remainder of the PRA period. In the event such abandoned facilities (gas compressors) have been replaced with electric compressors installed after October 1, 1998, and Northern reduces the applicable MID fuel percentages, Northern has the right to file to increase the applicable electric compression commodity rate.

RATE SCHEDULES FDD, PDD, IDD & SMS

Rate Schedule FDD		
Maximum Reservation Fee	1.7140	1/
Maximum Capacity Fee	0.3567	1/
Injection Charge - Firm	0.0149	
Withdrawal Charge - Firm	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule PDD		
Maximum Capacity Fee	0.3567	1/
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule IDD		
Maximum Monthly Inventory Charge	0.0887	1/
Injection Charge	0.0149	
Withdrawal Charge	0.0149	
Annual Rollover Fee	0.3567	1/
Rate Schedule SMS		
Reservation Fee	2.1800	
Commodity Rate	0.0208	

1/ Minimum Rate is zero.

Great Plains Natural Gas Co.
Market Conditions for Wahpeton's Natural Gas
May 2014

The principal gas sources of natural gas for Wahpeton, North Dakota are from the mid-continent area of the United States. The pricing for the majority of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The May monthly price for the NNG-Ventura Index is expected to be in the same range as the previous month index. The NNG-Ventura Index is based on negotiated trades during the last five business days of the month, commonly known as bid week, and reported by Platt's Inside FERC's Gas Market Report published the beginning of each month.

Despite the national storage levels being at their lowest level in the past 10 years, continuing strong production numbers appear to have offset the low levels and the need to inject into storage resulting in prices remaining in the same range as the previous month. The EIA reported storage levels nationwide as of April 18, 2014 were 52.9 percent below the five-year average and 48.0 percent below 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 18.

Independent Statistics & Analysis
U.S. Energy Information Administration

April 2014

Short-Term Energy and Summer Fuels Outlook (STEO)

Highlights

- During the April-through-September summer driving season this year, regular gasoline retail prices are forecast to average $3.57/gallon (gal). The projected monthly national average regular retail gasoline price falls from $3.66/gal in May to $3.46/gal in September. EIA expects regular gasoline retail prices to average $3.45/gal in 2014 and $3.37/gal in 2015, compared with $3.51/gal in 2013. The July 2014 New York Harbor reformulated blendstock for oxygenate blending (RBOB) futures contract averaged $2.85/gal for the five trading days ending April 3, 2014. Based on the market value of futures and options contracts for this key petroleum component of gasoline, there is a 3% probability that its price at expiration will exceed $3.35/gal, consistent with a monthly average regular-grade gasoline retail price exceeding $4.00/gal in July 2014 (see EIA Summer Fuels Outlook slideshow).

- The North Sea Brent crude oil spot price in March averaged near $110 per barrel (bbl) for the ninth consecutive month, while West Texas Intermediate (WTI) crude oil prices remained flat near $101/bbl. New pipeline capacity from the Midwest into the Gulf Coast helped reduce inventories at the Cushing, Oklahoma, storage hub to 27 million barrels by the end of March 2014, the lowest level since November 2009. The discount of WTI crude oil to Brent crude oil, which averaged more than $13/bbl from November through January, fell to $7/bbl in March. EIA expects the WTI discount to average $9/bbl in 2014 and $11/bbl in 2015.

- Natural gas working inventories on March 28, 2014, were 0.82 trillion cubic feet (Tcf), 0.88 Tcf (52%) below the level at the same time a year ago and 0.99 Tcf (55%) below the five-year average (2009-13). Henry Hub natural gas spot prices were volatile over the past few months, increasing from $3.95 per million British thermal units (MMBtu) on January 10 to a high of $8.15/MMBtu on February 10, before falling back to $4.61/MMBtu on February 27, and then bouncing back up to $7.98/MMBtu on March 4. EIA expects that the Henry Hub natural gas spot price, which averaged $3.73/MMBtu in 2013, will average $4.44/MMBtu in 2014 and $4.11/MMBtu in 2015.

Global Petroleum and Other Liquids

EIA projects world petroleum and other liquids supply to increase by 1.4 million barrels per day (bbl/d) in 2014 and 1.3 million bbl/d in 2015, with most of the growth coming from countries outside of the Organization of the Petroleum Exporting Countries (OPEC). The United States and Canada will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Countries outside the Organization for Economic Cooperation and Development (OECD), notably China, drive expected consumption growth.

EIA expects the combination of increased non-OPEC total liquids supply and OPEC noncrude supply to exceed world liquids demand growth over the next two years. The call on OPEC crude oil and global stocks falls from an average of 30.0 million bbl/d in 2013 to 29.5 million bbl/d in 2015 (Call on OPEC is world consumption less non-OPEC production and OPEC noncrude oil production). Forecast non-OPEC supply growth also contributes to an increase in global surplus crude oil production capacity from an average of 2.1 million bbl/d in 2013 to 3.6 million bbl/d in 2015.

Global Petroleum and Other Liquids Consumption. EIA estimates that global consumption grew by 1.2 million bbl/d in 2013, averaging 90.4 million bbl/d for the year. EIA expects global consumption to grow 1.2 million bbl/d in 2014 and 1.4 million bbl/d in 2015. Projected global oil-consumption-weighted real GDP, which increased by an estimated 2.3% in 2013, grows by 2.9% and 3.4% in 2014 and 2015, respectively.

Non-OECD countries account for all of the expected consumption growth in 2014 and nearly all of the growth in 2015. China is the leading contributor to projected global consumption growth, with consumption increasing by 400,000 bbl/d in 2014 and 430,000 bbl/d in 2015. However, China's economic and oil consumption growth rates have moderated compared with rates before 2012, when annual GDP growth exceeded 9% and oil consumption growth averaged almost 800,000 bbl/d from 2009 through 2011.

EIA expects lower OECD consumption in 2014, led by projected consumption declines in both Japan and Europe. EIA expects Japan's oil consumption to fall by an annual average of 150,000 bbl/d in 2014 and 2015, as the country continues to increase natural gas and coal consumption in the electricity sector and returns some nuclear power plants to service in the second half of 2014 and in 2015. EIA projects that OECD Europe's consumption, which fell by 100,000 bbl/d in 2013, will decline by 60,000 bbl/d in 2014 and then remain relatively flat in 2015. U.S. liquids consumption, which increased by 400,000 bbl/d in 2013, is expected to remain relatively flat in 2014 and then increase by 90,000 bbl/d in 2015.

Non-OPEC Supply. EIA estimates that non-OPEC liquids production grew by 1.3 million bbl/d in 2013, averaging 54.0 million bbl/d for the year. EIA expects non-OPEC liquids production to grow by 1.6 million bbl/d in 2014 and 1.3 million bbl/d in 2015. EIA forecasts production from

the United States and Canada to grow by a combined annual average of 1.4 million bbl/d in 2014 and 1.2 million bbl/d in 2015. EIA estimates that the Former Soviet Union's production will rise by an annual average of 0.16 million bbl/d over the forecast period, led by Russia in 2014 and Kazakhstan in 2015.

Unplanned supply disruptions among non-OPEC producers averaged 0.6 million bbl/d in March 2014, about 40,000 bbl/d lower than in February as a result of fewer outages in the North Sea and Indonesia. South Sudan, Syria, and Yemen accounted for almost 90% of total non-OPEC supply disruptions. EIA does not assume a disruption to oil supply or demand as a result of ongoing events in Ukraine.

OPEC Supply. EIA estimates that OPEC crude oil production averaged 30.0 million bbl/d in 2013, a decline of 0.9 million bbl/d from the previous year, primarily reflecting increased outages in Libya, Nigeria, and Iraq, along with strong non-OPEC supply growth. EIA expects OPEC crude oil production to fall by 0.2 million bbl/d in both 2014 and 2015, as a result of supply disruptions in OPEC and cutbacks in crude oil production to accommodate increased supplies in non-OPEC countries.

Unplanned crude oil supply disruptions among OPEC producers averaged 2.6 million bbl/d in March 2014, 0.3 million bbl/d higher than the previous month. Libya continues to experience swings in its production, contributing to changes in the OPEC disruption estimate. Unplanned disruptions in Iraq escalated in March, averaging nearly 0.4 million bbl/d, as a result of attacks on the Kirkuk-Ceyhan pipeline.

EIA expects that OPEC surplus capacity, which is concentrated in Saudi Arabia, will average 2.3 million bbl/d in 2014 and 3.6 million bbl/d in 2015. This build in surplus capacity reflects production cutbacks by some OPEC members adjusting for the higher supply from non-OPEC producers. These estimates do not include additional capacity that may be available in Iran but is currently offline because of the effects of U.S. and European Union sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories totaled 2.58 billion barrels by the end of 2013, equivalent to roughly 55 days of consumption. Projected OECD oil inventories rise to 2.61 billion barrels at the end of 2014 and 2.64 billion barrels at the end of 2015.

Crude Oil Prices. Brent crude oil spot prices in March averaged $107/bbl. This was the ninth consecutive month Brent crude oil spot prices averaged between $107/bbl and $112/bbl. The Brent crude oil price is projected to average $105/bbl and $101/bbl in 2014 and 2015, respectively.

The WTI crude oil spot price, which fell to an average of $95/bbl in January 2014, increased to an average of $101/bbl in February and March as a result of strong Midwestern refinery runs

and the startup of the Marketlink pipeline moving crude from Cushing to the Gulf Coast. EIA expects that WTI crude oil prices will average $96/bbl in 2014, $1/bbl higher than in last month's STEO, and $90/bbl during 2015. The discount of WTI crude oil to Brent crude oil, which averaged more than $13/bbl from November 2013 through January 2014, fell to an average of nearly $7/bbl in March 2014. EIA expects the discount of WTI crude oil to Brent crude oil to grow in the coming months to an average $9/bbl in 2014 and $11/bbl in 2015, reflecting the economics of transporting and processing the growing production of light sweet crude oil in U.S. and Canadian refineries.

Energy price forecasts are highly uncertain, and the current values of futures and options contracts suggest that prices could differ significantly from the forecast levels (*Market Prices and Uncertainty Report*). WTI futures contracts for July 2014 delivery, traded during the five-day period ending April 3, 2014, averaged $99/bbl. Implied volatility averaged 17%, establishing the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in June 2014 at $85/bbl and $115/bbl, respectively. Last year at this time, WTI for July 2013 delivery averaged $96/bbl and implied volatility averaged 18%. The corresponding lower and upper limits of the 95% confidence interval were $82/bbl and $113/bbl.

U.S. Petroleum and Other Liquids

U.S. Liquid Fuels Consumption. Total U.S. liquid fuels consumption rose by an estimated 400,000 bbl/d (2.1%) in 2013. Consumption of hydrocarbon gas liquids (HGL) registered the largest gain, increasing by 150,000 bbl/d (6.4%). Motor gasoline consumption grew by 90,000 bbl/d (1.1%), the largest increase since 2006. Stronger-than-expected growth in highway travel during the second half of 2013 contributed to that increase. Distillate fuel consumption increased by 90,000 bbl/d (2.5%), reflecting colder weather and domestic economic growth.

Projected total liquid fuels consumption remains flat in 2014. Motor gasoline consumption remains largely unchanged as the recent strong growth in highway travel slows and continued improvements in new-vehicle fuel economy boost overall fuel efficiency growth. Distillate fuel oil consumption rises 20,000 bbl/d (0.4%). In 2015, total liquid fuels consumption increases by 90,000 bbl/d (0.5%), driven primarily by increasing transportation demand for distillate fuel oil and industrial demand for HGL.

U.S. Liquid Fuels Supply. Weather conditions in the Lower 48 states during December 2013 and January 2014 caused operational issues in key producing regions. While a temporary slowdown in well completion activity resulted in flat crude oil production during those months, much of the production slowdown is expected to be made up by accelerated completion activity over the next few months.

Aside from seasonal issues, EIA expects strong crude oil production growth, primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015.

Forecast production increases from an estimated 7.4 million bbl/d in 2013 to 8.4 million bbl/d in 2014 and 9.1 million bbl/d in 2015. The highest historical annual average U.S. production level was 9.6 million bbl/d in 1970.

Crude oil production from the Bakken formation in North Dakota and Montana averaged 0.9 million bbl/d in 2013. Production in the Eagle Ford formation in South Texas averaged 1.1 million bbl/d in 2013, reaching an estimated 1.2 million bbl/d in December 2013.

Summer Transportation Fuels Outlook

U.S. Gasoline and Diesel Fuel Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.58/gal last summer, will average $3.57/gal during the current summer (April through September) driving season. The projected monthly average regular retail gasoline price falls from $3.66/gal in May to $3.46/gal in September. Diesel fuel prices, which averaged $3.89/gal last summer, are projected to average $3.87/gal this summer. Daily and weekly national average prices can differ significantly from monthly and seasonal averages, and there are also significant differences across regions, with monthly average prices in some areas exceeding the national average price by 30 cents/gal or more. Any unforeseen refinery outages or other disruptions to supply also have the potential to increase regional product prices beyond forecast levels in the short term.

Because taxes and retail distribution costs are generally stable, movements in gasoline and diesel prices are driven primarily by changes in both crude oil prices and wholesale margins. The retail price projections reflect falling prices for crude oil, best represented by the Brent crude oil price, which averages about $105/bbl ($2.49/gal) this summer compared with the $107/bbl ($2.54/gal) average of last summer. Any difference between actual crude oil prices and EIA's forecast would be reflected in the price of motor fuels. Absent other factors specific to the gasoline and diesel fuel markets, each dollar per barrel of sustained change in crude oil prices compared with the forecast translates into approximately a 2.4-cent-per-gallon change in product prices.

EIA expects wholesale gasoline margins (the difference between the wholesale price of gasoline and the Brent crude oil price) will average 38 cents/gal this summer, about 3 cents higher than last summer and 4 cents higher than the previous five-summer average. Forecast wholesale diesel fuel margins are 46 cents/gal, 1 cent below last summer's level and 9 cents higher than the previous five-summer average.

As in the case of crude oil, the market's expectation of uncertainty in monthly average gasoline prices is reflected in the pricing and implied volatility of futures and options contracts. New York Harbor RBOB futures contracts for July 2014 delivery traded over the five-day period ending April 3 averaged $2.85/gal. The probability that the RBOB futures price will exceed $3.35/gal (consistent with a U.S. average regular gasoline retail price above $4.00/gal) in July 2014 is about 3%.

Motor Gasoline. During this summer driving season (April through September), projected motor gasoline consumption remains unchanged from last summer's average of 9.0 million bbl/d. Year-over-year increases in highway travel, projected to be 0.7%, are offset by an increase in fleet-wide fuel efficiency. Finished motor gasoline is supplied by four sources: domestic refinery output, fuel ethanol blending, net imports of gasoline and gasoline blending components, and primary inventories. EIA expects that domestic refinery production, including gasoline blendstock output, will increase by 60,000 bbl/d from last summer. Fuel ethanol blending into gasoline is projected to decrease by 3,000 bbl/d from last summer's level to 870,000 bbl/d, which is 9.7% of total gasoline consumption. Projected total gasoline net imports (including blending components) average 240,000 bbl/d, down 7% from last summer.

At the onset of the summer driving season (April 1), total gasoline stocks were down 10 million barrels from a year ago and down 5 million barrels from the five-year average for beginning-of-season stocks. Stock withdrawals have not been a significant motor gasoline supply source for the summer season in recent years, having averaged only 35,000 bbl/d during the previous five summer seasons. This summer, total gasoline stocks are projected to remain almost unchanged, compared with a 31,000-bbl/d draw last summer. Moreover, the absence of a seasonal pattern differs from that of last summer, which saw a sizable draw on inventories during the third quarter. As a result, total gasoline inventories this summer are projected to end the season at 215 million barrels, 4 million barrels below last year's level but 1 million barrels above the five-year average.

Diesel Fuel. Projected consumption of distillate fuel, which includes diesel fuel and heating oil, averages 3.8 million bbl/d this summer, up 37,000 bbl/d (1.0%) from last summer. That growth is driven by increasing manufacturing output and foreign trade.

Distillate fuel is supplied by four sources: domestic refinery output, biodiesel blending, primary inventories, and net imports. EIA expects refinery output of distillate fuel will average 4.9 million bbl/d this summer, up 150,000 bbl/d from last summer. Biodiesel has been a small part of the distillate pool, averaging 93,000 bbl/d last summer and forecast to average about 78,000 bbl/d this summer. Projected distillate fuel net exports average 1.15 million bbl/d this summer, up from 1.06 million bbl/d last summer.

Distillate inventories are projected to start the summer at 112.6 million barrels, down from the 118.6 million barrels recorded at the start of last summer and the five-year average of 138.7 million barrels. Distillate inventories typically build during the summer season in preparation for the heating season. This summer, the build is forecast to average 89,000 bbl/d, up substantially from the 54,000 bbl/d build recorded last summer, but similar to the five-year average summer build of 60,000 bbl/d. End-of-summer stocks are 128.9 million barrels, up slightly from the 128.6 million barrels recorded at the end of last summer, but well below the five-year end-of-summer average of 149.8 million barrels.

Natural Gas

Following late-winter cold weather, working natural gas in storage ended March at an estimated 826 Bcf, the lowest level in 11 years. EIA now expects a large rebuild over the injection season, with inventories ending October at 3,422 Bcf. This represents a record stock build of nearly 2,600 Bcf. Expectations for lower demand from the electric power sector compared with the past several years, as well as increasing production, should help enable a record-high stock build. This month's STEO revises upward the outlook for natural gas marketed production in both 2014 and 2015. While production dipped in the winter months due to freeze-offs in various locations, recent outside data sources indicate production has bounced back and is exceeding record highs set in November.

U.S. Natural Gas Consumption. EIA expects total natural gas consumption will average 72.1 Bcf per day (Bcf/d) in 2014, an increase of 0.7 Bcf/d from 2013. Increased residential, commercial, and industrial use offsets declines from the electric power sector, which are related to higher natural gas prices. In 2015, total natural gas consumption falls by 0.4 Bcf/d as a decline in residential and commercial consumption more than offsets consumption growth in the industrial and electric power sectors. EIA expects natural gas consumption in the power sector to increase to 22.8 Bcf/d in 2015 with the retirement of some coal plants.

U.S. Natural Gas Production and Trade. EIA expects natural gas marketed production will grow by an average rate of 3.0% in 2014 and 1.5% in 2015. Rapid natural gas production growth in the Marcellus formation is contributing to falling natural gas forward prices in the Northeast, which often fall even with or below Henry Hub prices outside of peak winter demand months. Consequently, some drilling activity may move away from the Marcellus back to Gulf Coast plays such as the Haynesville and Barnett, where prices are closer to the Henry Hub spot price.

Liquefied natural gas (LNG) imports have declined over the past several years because higher prices in Europe and Asia are more attractive to sellers than the relatively low prices in the United States. Several companies are planning to build liquefaction capacity to export LNG from the United States. Cheniere Energy's Sabine Pass facility is planned to be the first to liquefy natural gas produced in the Lower 48 states for export. The facility has a total liquefaction capacity of 3 Bcf/d and is scheduled to come online in stages beginning in late 2015.

Growing domestic production over the past several years has displaced some pipeline imports from Canada, while exports to Mexico have increased. EIA projects net imports of 3.7 Bcf/d in 2014 and 3.0 Bcf/d in 2015, which would be the lowest level since 1987. Over the longer term, the EIA *Annual Energy Outlook 2014* projects the United States will be a net exporter of natural gas beginning in 2018.

U.S. Natural Gas Inventories. Natural gas working inventories fell by 74 Bcf to 822 Bcf during the week ending March 28, 2014. Colder-than-normal temperatures and a few late-season

winter storms during the month resulted in increased heating demand, prompting larger-than-normal withdrawals. Stocks are now 878 Bcf less than last year at this time and 992 Bcf less than the five-year (2009-13) average for this time of year. Total stocks, as well as stocks in all three regions, are currently less than their five-year (2009-13) minimums.

U.S. Natural Gas Prices. Natural gas spot prices averaged $4.90/MMBtu at the Henry Hub in March, down $1.10/MMBtu from February, as weather in March was less extreme than the previous month, but still colder than normal. EIA projects that spot prices will continue to decline in the spring. Projected Henry Hub natural gas prices average $4.44/MMBtu in 2014 and $4.11/MMBtu in 2015.

Natural gas futures prices for July 2014 delivery (for the five-day period ending April 3, 2014) averaged $4.46/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for July 2014 contracts at $3.40/MMBtu and $5.87/MMBtu, respectively. At this time last year, the natural gas futures contract for July 2013 averaged $4.07/MMBtu and the corresponding lower and upper limits of the 95% confidence interval were $3.16/MMBtu and $5.23/MMBtu.

Coal

Severe winter weather, increases in oil and grain rail traffic, and track work have combined to constrain coal shipments via rail from Powder River Basin (PRB) coal producers to power generators. Weather disruptions began early in the winter season, with October snowfall disrupting shipments from the PRB. Severe weather continued through the quarter and shipments from the Southern PRB and Colorado/Utah significantly declined.

Increases in other rail traffic have helped to create bottlenecks on western rail systems. According to data from the Association of American Railroads, increased crude oil shipments, primarily from the Bakken shale play, and increased grain shipments have taxed rail infrastructure in the region. Soaring volume on Burlington Northern Santa Fe (BNSF) Corporation's main line in North Dakota, coupled with weather issues, prompted Basin Electric Power Cooperative to move coal in North Dakota by truck for 30 days.

The severe winter weather exacerbated the situation by increasing power demand and depleting coal inventories. Spot purchases of coal, which could aid in replenishing stockpiles, are competing for rail service, as the railroads are struggling to catch up with contracted shipments that have been delayed. Some utilities have reportedly taken coal units offline in order to conserve stockpiles. Coal sourced from other basins, primarily the Illinois and Central Appalachian, may be called upon to help replenish stockpiles.

U.S. Coal Supply. EIA projects coal production will grow 4.1% to 1,024 million short tons (MMst) in 2014. The increase this year is primarily a result of higher consumption. Coal production is projected to fall by less than 1% in 2015 to 1,022 MMst, but Appalachian coal production is

projected to decline by 2.7%. Interior production is expected to remain steady, while Western production grows by 0.9%.

U.S. Coal Consumption. EIA estimates total coal consumption for 2013 totaled 925 MMst, a 4.0% increase over 2012. The increase was primarily a result of increased consumption in the electric power sector due to higher natural gas prices. Consumption continues to grow at a rate of 4.2% to 964 MMst in 2014 as electricity demand grows and natural gas prices remain well above their 2012 level. Total coal consumption is projected to decline by 2.4% in 2015, as retirements of coal power plants rise in response to the implementation of the Mercury and Air Toxics Standards, and generation from renewable resources (wind, hydro, biomass, geothermal, and solar) grows by more than 3%.

U.S. Coal Exports. Exports are projected to total 101 MMst in 2014, making it the fourth consecutive year with more than 100 MMst of coal exports. This would be the second time that exports have exceeded 100 MMst for four consecutive years, with the first being from 1989 through 1992. Projected exports fall back to 96 MMst in 2015. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing coal output in other coal-exporting countries, and falling international coal prices are the primary reasons for the expected decline in U.S. coal exports.

U.S. Coal Prices. Annual average coal prices to the electric power industry fell for the second consecutive year, from $2.38/MMBtu in 2012 to $2.35/MMBtu in 2013. EIA forecasts average delivered coal prices of $2.35/MMBtu in 2014 and $2.36/MMBtu in 2015.

Electricity

Periods of extreme cold in the Midwest and Northeast this past winter caused spikes in wholesale electricity prices at certain times of peak demand. In early January, the low temperatures and constraints on natural gas delivery led to average day-ahead prices close to $250/megawatthour in the New England and New York wholesale power markets. These high prices encouraged generation from power plants that have the capability to burn petroleum, leading to the highest level of generation from petroleum liquids in the Northeast since January 2006. However, these spikes in petroleum-fired generation were only temporary, and the fuel accounts for a very small share of total generation.

U.S. Electricity Consumption. The cold winter weather was a primary driver of the estimated 4.3% year-over-year increase in total U.S. retail sales of electricity during the first quarter of 2014. Year-over-year growth was especially strong in the residential sector, which grew by an estimated 7.3%. For the upcoming summer months, EIA projects residential sales during the second and third quarters will average 0.6% more than last summer. This growth is driven by a 5.8% increase in summer cooling degree days, offset slightly by efficiency improvements in air conditioning, lighting, and other electricity uses.

U.S. Electricity Generation. Preliminary EIA data indicate that 4.7 gigawatts (GW) of coal capacity was retired during 2013 (following 10.3 GW of coal capacity retirements during 2012). Despite these retirements, coal generators have increased their utilization of existing capacity in recent months so that the share of total generation fueled by coal during the first quarter of 2014 rose to 41.4% from 40.0% during the first quarter of 2013. This increase in utilization of coal-fired capacity was driven primarily by rising natural gas fuel costs, which in turn drove down the share of generation fueled by natural gas to 23.8% during the first quarter of 2014 from 25.6% during the same period last year. EIA projects total U.S. electricity generation will average 11.3 terawatthours per day in 2014, an increase of 1.8% from last year. Coal fuels 40.3% of total generation during 2014 while natural gas supplies 26.5%.

U.S. Electricity Retail Prices. EIA expects the U.S. residential price of electricity to average 12.4 cents per kilowatthour during 2014, an increase of 2.6% from 2013. Price increases are highest in the New England (7.1%) and Middle Atlantic (4.0%) regions.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewables used for electricity and heat generation will grow by about 3.7% in 2014. Hydropower is projected to increase by 3.6%, while nonhydropower renewables rise by 3.7%. In 2015, projected renewables consumption for electric power and heat generation increases by 3.0% from 2014, as a 1.0% decrease in hydropower is combined with a 5.2% increase in nonhydropower renewables.

EIA estimates that wind power capacity will increase by 8.9% in 2014 and 15.5% in 2015, reaching about 66 gigawatts (GW) at the end of 2014 and 76 GW at the end of 2015. Electricity generation from wind is projected to contribute 4.5% of total electricity generation in 2015.

EIA expects continued robust growth in solar electricity generation, although the amount of utility-scale generation remains a small share of total U.S. generation at about 0.5% in 2015. While solar growth has historically been concentrated in customer-sited distributed generation installations, utility-scale solar capacity doubled in 2013. EIA currently expects that utility-scale solar capacity will increase by approximately 56% between year-end 2013 and year-end 2015. Approximately 70% of this new capacity is being built in California. However, customer-sited photovoltaic capacity growth, which the STEO does not forecast, is expected to exceed utility-scale solar growth between 2013 and 2015, according to EIA's *Annual Energy Outlook 2014*.

U.S. Liquid Biofuels. Logistical constraints, primarily railroad delays resulting from extreme winter temperatures in the Midwest, led ethanol production to decline from an average of about 900,000 bbl/d in January and February 2014 to 890,000 bbl/d in March 2014. These logistical problems led to sharp ethanol price increases across the United States in March, but especially in PADD 1 (East Coast). These constraints are expected to be short-lived as warmer

temperatures arrive and ethanol production rebounds to a forecast average of 908,000 bbl/d during 2014.

Biodiesel production, which averaged 64,000 bbl/d (1.0 billion gallons per year) in 2012, rose to 104,000 bbl/d (135 million gallons) in December 2013, 7 million gallons higher than in November. A biodiesel production tax credit expired at the end of 2013. Biodiesel production averaged 87,000 bbl/d in 2013 and is forecast to average 75,000 bbl/d in 2014 and 77,000 bbl/d in 2015.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels increased by 2.1% in 2013 from the previous year. Emissions are forecast to rise 1.9% in 2014, followed by a decline in 2015 of 0.8%. The increase in emissions in 2013 and 2014 reflects growth in coal consumption because of its higher use in electric power generation. Coal emissions are projected to decline by 2.5% in 2015 with increasing coal plant retirements.

U.S. Economic Assumptions

The U.S. Bureau of Economic Analysis (BEA) revised the fourth quarter 2013 gross domestic product estimate upwards, now showing growth at an annual rate of 2.6%, compared to the 2.4% growth of the previous estimate. Consumption expenditures (primarily due to increases in health care spending and utilities) and corporate profits came in higher than the previous fourth quarter 2013 estimate. BEA also reported that real personal consumption expenditures rose 0.2% from January to February, exceeding the 0.1% rise from December to January. Real disposable personal income rose 0.3% from January to February. New orders for durable goods rose 2.2% over the same time period, reversing declines in the two previous months according to the U.S. Census Bureau. The gain was driven primarily by transportation goods, with a more modest a 0.2% monthly gain for other orders. Finally, the U.S. Department of Housing and Urban Development reported that sales of new single-family houses in February were 3.3% below the January level, and 1.1% below the February 2013 estimate.

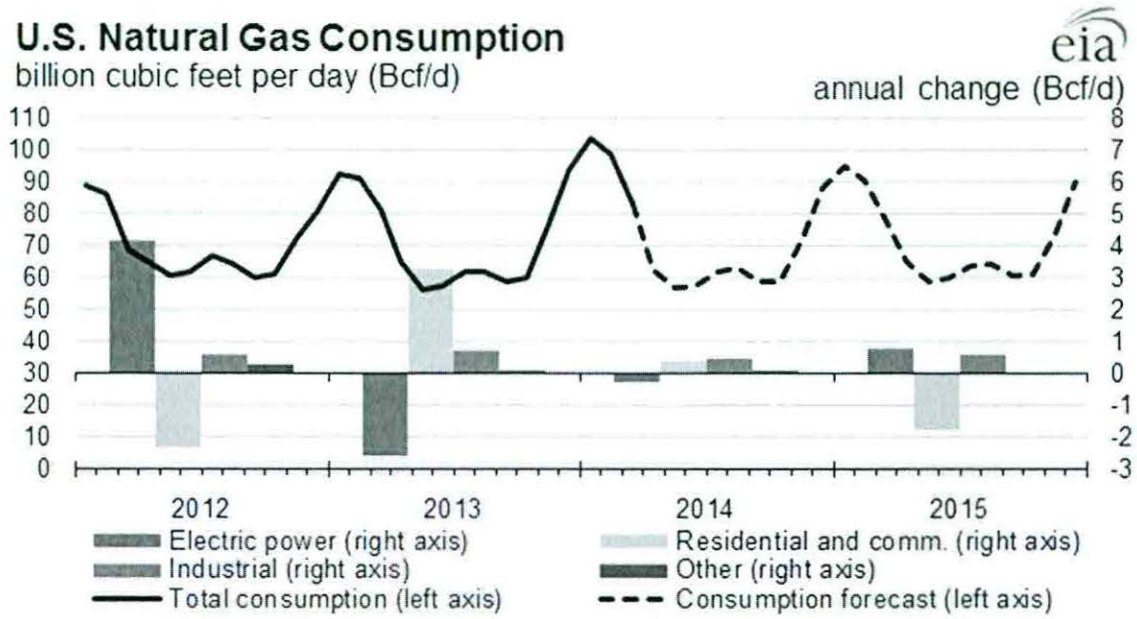
EIA uses the IHS/Global Insight macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Production and Income. Forecast real GDP grows by 2.5% in 2014 and 3.2% in 2015. Even though forecast real GDP growth accelerates over the next two years, it is only in 2015 that GDP growth exceeds the economy's average annual growth of 3% from 1990 through 2007. Forecast real disposable income increases 2.2% in 2014 and 3.6% in 2015. Total industrial production grows at 2.7% in 2014 and is projected to grow 4.0% in 2015.

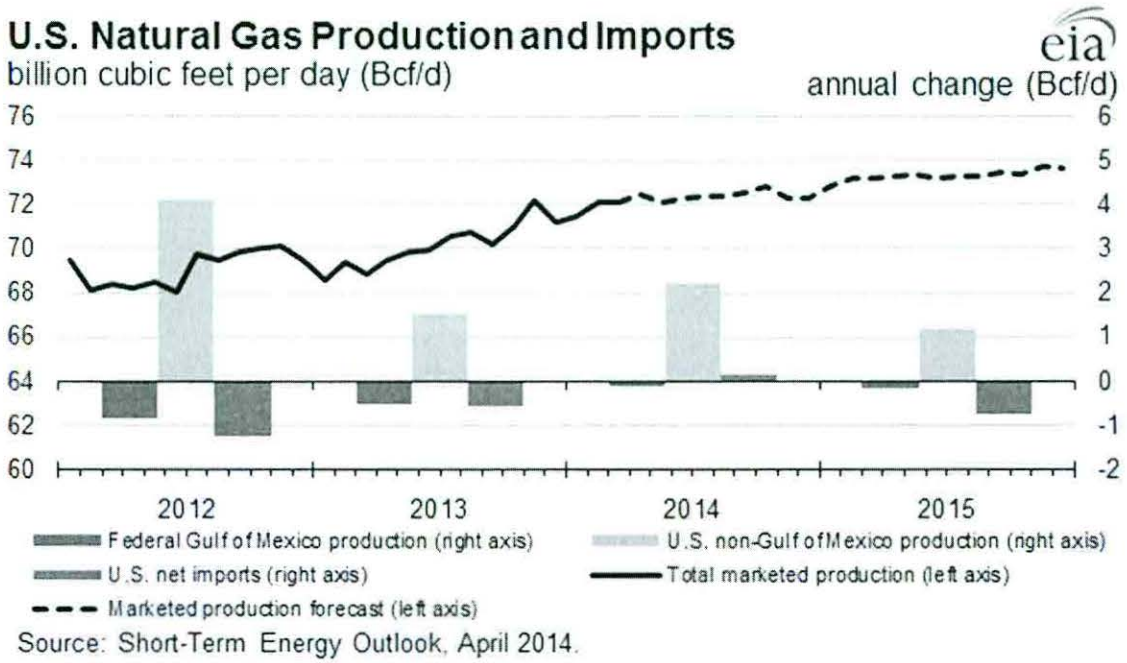
Expenditures. Private real fixed investment growth averages 6.1% and 9.7% over 2014 and 2015, respectively, with equipment spending accounting for most of investment's growth. Real consumption expenditures grow at the same rate as real GDP in 2014, at 2.5%, and are below the rate of real GDP growth in 2015, at 2.9%. Durable goods expenditures drive the

consumption spending. Export growth is 4.2% and 4.1% over the same two years, while import growth is 2.4% in 2014 and 6.5% in 2015. Total government expenditures fall 0.6% in 2014, but increase by 0.4% in 2015.

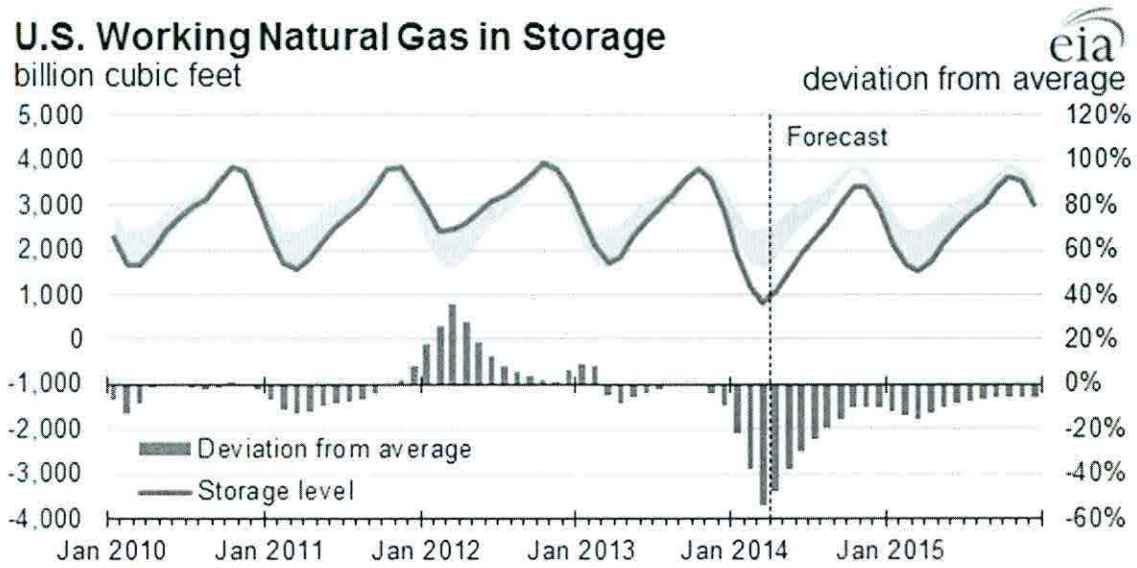
Employment, Housing, and Prices. Projected growth in nonfarm employment averages 1.6% in 2014 and 2.1% in 2015. This is accompanied by a gradually declining unemployment rate that reaches 6.2% by the end 2014 and 5.7% at the end of 2015, the same as projected last month. Housing starts grow an average of 17.2% and 33.9% in 2014 and 2015, respectively. Both consumer and producer price indexes continue to increase at a moderate pace, as wages continue to show modest gains.



Source: Short-Term Energy Outlook, April 2014.



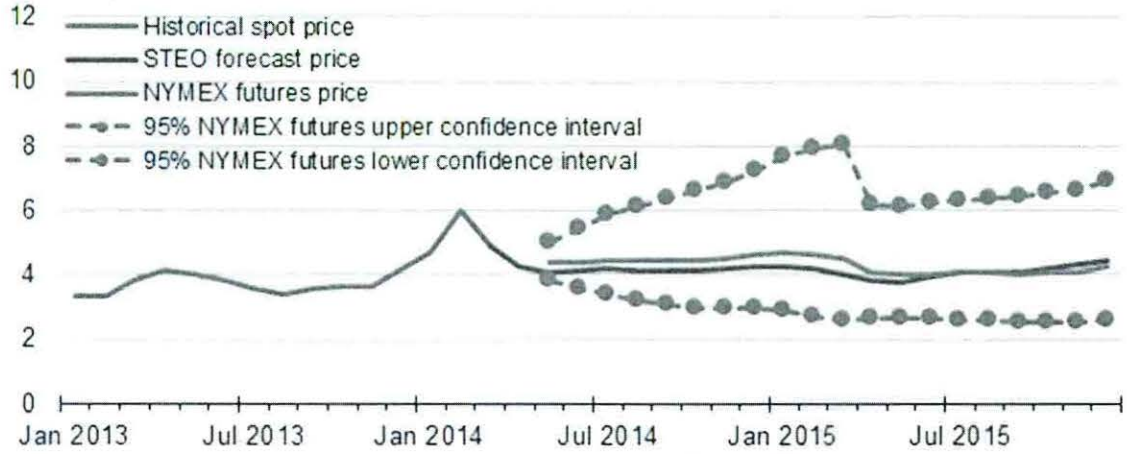
Source: Short-Term Energy Outlook, April 2014.



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2009 - Dec. 2013.
Source: Short-Term Energy Outlook, April 2014.

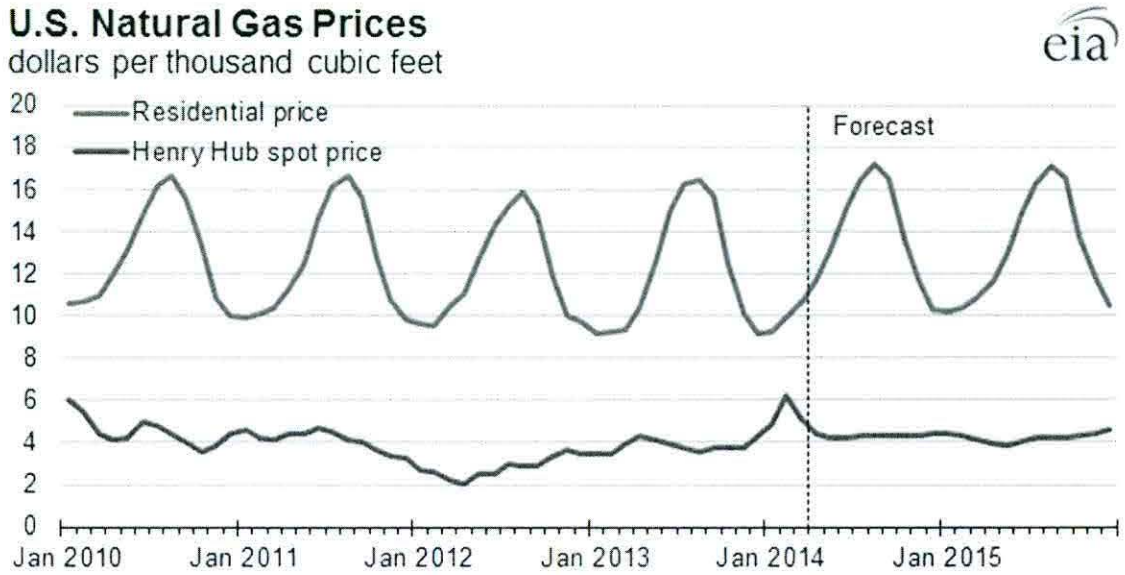
Henry Hub Natural Gas Price

dollars per million Btu



Note: Confidence interval derived from options market information for the 5 trading days ending Apr. 3, 2014. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, April 2014.



Source: Short-Term Energy Outlook, April 2014.

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/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount		Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013										**$303,311**
May 2013	($12,469)	0	$1,860	($10,609)	21,400	$1.0137	$21,692		($32,301)	271,010
June	4,837	0	1,626	6,463	9,214	0.9614	9,167	2/	(2,704)	268,306
July	19,011	0	1,601	20,612	6,004	0.9614	5,772		14,840	283,146
August	16,638	(17,889)	1,701	450	5,505	0.9614	5,293		(4,843)	278,303
September	296	0	1,658	1,954	5,691	0.9614	5,471		(3,517)	274,786
October	5,896	0	1,625	7,521	8,206	0.9614	7,889		(368)	274,418
November	1,647	0	1,618	3,265	21,099	0.9614	20,285		(17,020)	257,398
December	45	0	1,501	1,546	42,237	0.9614	40,607		(39,060)	218,338
January 2014	35,892	0	1,244	37,136	59,753	0.9614	57,447		(20,311)	198,027
February	117,838	0	1,138	118,976	56,223	0.9614	54,053		64,923	262,950
March	146,902	0	1,644	148,546	48,181	0.9614	46,321		102,225	365,175
Total	$336,533	(17,889)	$17,216	$335,860	283,513		$273,997		$61,864	
Balance @ March 31, 2014										**$365,175**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,911.4 Mcf @ $1.0137 and 3,302.1 Mcf @ $0.9614.

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/	Total Net Additions	Actual Mcf Sales	Adjustment Per Mcf	Total Adjustment Amount	Net Change-Additions less Adjustment	Cumulative Balance
Balance @ April 30, 2013									**$4,747**
May 2013	($19,391)	0	($4)	($19,395)	49,736	($0.2915)	($14,498)	($4,897)	(150)
June	(13,383)	0	(46)	(13,429)	23,704	0.0274	(4,253) 2/	(9,176)	(9,326)
July	(9,266)	0	(115)	(9,381)	17,577	0.0274	482	(9,863)	(19,189)
August	(1,454)	0	(188)	(1,642)	14,808	0.0274	406	(2,048)	(21,237)
September	(28,851)	0	(203)	(29,054)	16,181	0.0274	443	(29,497)	(50,734)
October	4,119	0	(416)	3,703	26,694	0.0274	731	2,972	(47,762)
November	5,534	0	(395)	5,139	56,950	0.0274	1,560	3,579	(44,183)
December	13,820	0	(373)	13,447	81,821	0.0274	2,242	11,205	(32,978)
January 2014	29,696	0	(300)	29,396	56,375	0.0274	1,545	27,852	(5,126)
February	144,559	0	(104)	144,455	48,233	0.0274	1,322	143,133	138,007
March	207,848	0	921	208,769	58,629	0.0274	1,606	207,163	345,170
Total	$333,231	0	($1,223)	$332,008	450,708		($8,414)	$340,423	
Balance @ March 31, 2014									**$345,170**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 15,372.2 Mcf @ ($0.2915) and 8,331.7 Mcf @ $0.0274.