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

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August 29, 2013

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

Re: Cost of Gas Adjustment (COG)
September 2013

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 (90th Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (90th Revised Sheet No. 8), showing the September 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is a decrease of $0.1061 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for September 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has decreased $0.1061 since the last COG filing.

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, 2013 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
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
90th Revised Sheet No. 1.1
Canceling 89th Revised Sheet No.1.1

RATE SUMMARY SHEET

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	$6.1400	$7.4140
			Over 10 MCF	1.0540		7.1940
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.1400	$8.3140
			Over 10 MCF	1.9540		8.0940
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.6830	$4.8221
			Next 2,600 MCF	0.8931		4.5761
			Over 3,000 MCF	0.7411		4.4241
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.6830	$5.7221
			Next 2,600 MCF	1.7931		5.4761
			Over 3,000 MCF	1.6411		5.3241
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.6830	$4.9221
Transportation Service	5	$3.50 per month	First 400 MCF	$1.1391		$1.1391
			Next 2,600 MCF	0.8931		0.8931
			Over 3,000 MCF	0.7411		0.7411

Date Filed: August 29, 2013

Effective Date: Service rendered on and after September 1, 2013

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
90th Revised Sheet No. 8
Canceling 89th 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	$0.0658	$5.1191	$0.0000	$5.1849	$5.1191	$0.0000	$5.1191
Accumulated Adj.	1.4722	(1.3724)	0.9614	1.0612	(1.3574)	0.0274	(1.3300)
Current Adj.	0.0000	(0.1061)	0.0000	(0.1061)	(0.1061)	0.0000	(0.1061)
Total Adj.	1.4722	(1.4785)	0.9614	0.9551	(1.4635)	0.0274	(1.4361)
Total Rate	$1.5380	$3.6406	$0.9614	$6.1400	$3.6556	$0.0274	$3.6830

Date Filed: August 29, 2013

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Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2013

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	8,000		$3.4671	12	$332,842	$0.2373
FT-A - Zone 1-1	500		3.4671	5	8,668	0.0062
FT-A - Zone 1-2	4,500		4.5871	5	103,210	0.0736
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
TFX Seasonal	2,000		15.1530	5	151,530	0.1080
TFX - Winter	13,000		15.1530	5	984,945	0.7023
TFX - Summer	13,000		5.6830	7	517,153	0.3687
LMS Demand 2/						0.0150
Total Demand Charges					$2,136,019	1.5380
Estimated Weighted Average Commodity Cost	1,402,522	1/	3.6406		5,106,022	3.6406
Gas Cost Reconciliation Adjustment						0.9614
Total Current Firm Gas Cost					$7,242,041	6.1400
Base Cost of Gas						5.1849
Accumulated Adjustment						$0.9551

Interruptible	
Estimated Weighted Average Commodity Cost	$3.6406
Gas Cost Reconciliation Adjustment	0.0274
LMS Demand 2/	0.0150
Total Current Interruptible Gas Cost	3.6830
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.4361)

1/ Three year normalized average mcf sales
2/ Amount divided by 2010-2012 average interruptible sales volumes plus 2010-2012 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0150

GREAT PLAINS NATURAL GAS CO.
WAHPETON
COST OF GAS ADJUSTMENT
SEPTEMBER 2013

Rates Effective September 1, 2013	$/Dk	
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	15.1530	Per dk/Mo.
TFX Seasonal	15.1530	Per dk/Mo.
LMS Demand	1.0000	Per dk/Mo.
Estimated Weighted Average Commodity Cost:	3.6406	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	$5.1849	Per Mcf
Interruptible:		
Commodity	$5.1191	Per Mcf

1/ Demand base rate calculation: 4,768 X 12 X $0.8100 / 707,222

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	$3.7671
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

Viking Gas Transmission Company
FERC Gas Tariff
Volume No. 1

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	$0.0018	$0.0148	0.36%
Zone 1-2	$0.0130	$0.0018	$0.0148	0.47%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	0.36%
Zone 1-2	$0.1737	$0.0018	$0.1755	0.47%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.11%
Minimum Rate	$0.0130	$0.0018	$0.0148	

1/ Pursuant to Section 19 of the General Terms and Conditions, the Annual Charge Adjustment (ACA) Surcharge of $0.0018 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: 0.06% for Zone 1-1, 0.08 % for Zone 1-2, and 0.02% 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	$1.0000		$1.0000
LMS – Daily Overrun Rate	$0.1737		$0.1737
LMS – Load Management Cost Reconciliation Adjustment		$0.0001	

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	$0.1737	$0.0000
RPL Service:		
Daily Reservation Rate	$0.1737	$0.0000

RATE SCHEDULE TF

	MARKET-TO-MARKET			FIELD-TO-FIELD/MARKET DEMARCATION
		TF12		
RESERVATION RATES	TF12 Base	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/				Field Mileage 5/		Carlton			
TF12 Base, TF12 Var., TF5 & TFF		Market Area 3/		Rate per 100 miles		Surcharge 4/		Out-of Balance 3/	
Receipt Point	Delivery Point	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum	Minimum
Market	Market	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

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. 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/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 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.

RATE SCHEDULES TFX and LFT

RESERVATION RATES	MARKET-TO-MARKET Apr-Oct	MARKET-TO-MARKET Nov-Mar	FIELD-TO-FIELD Apr-Oct	FIELD-TO-FIELD 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	0.0377	0.0208			0.0175	0.0000	0.0377	0.0208
Field	Market	0.0377	0.0208	0.0122	0.0040	0.0175	0.0000		
Market	Field			0.0122	0.0040				
Field	Field			0.0122	0.0040			0.0294	0.0108

GULF COAST	Reservation 1/ Maximum	Reservation 1/ Minimum	Commodity 6/ Maximum	Commodity 6/ Minimum	Out-of-Balance 6/ Maximum	Out-of-Balance 6/ Minimum
MOPS Gathering	1.0514	0.0000	0.0018	0.0018	0.0018	0.0018
MOPS Transmission	1.5337	0.0000	0.0018	0.0018	0.0018	0.0018
Tivoli - Downstream	0.6827	0.0000	0.0018	0.0018	0.0018	0.0018
Other Gulf Coast	4.8169	0.0000	0.0018	0.0018	0.0018	0.0018

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. 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/ Maximum and Minimum rates include ACA of $0.0018 and the Market Area Electric Compression charge of $0.0000 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 $0.0018.

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

Fuel Percentages/Electric Compression Rates

	Percentages
FUEL PERCENTAGES:	1/
Market Area (including Out-of-Balance)	0.87%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.33% 4/ 5/
FDD Storage Fuel	1.55%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0000
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, 2012.

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
September 2013

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 September monthly price for the NNG-Ventura Index is expected to be in the same price 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.

The combination of moderate or below normal temperatures in the first half of August were partially offset by above normal temperatures during the second half of August, resulting in higher than expected injections into storage, which likely contributed to the index remaining in the same price range as the previous month. The national storage levels are now above the five year average. The EIA reported storage levels nationwide as of August 16, 2013 were 1.5 percent above the five-year average and 7.2 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

August 2013

Short-Term Energy Outlook (STEO)

Highlights

- Crude oil prices increased during the first three weeks of July 2013 as world oil markets tightened in the face of seasonal increases in world consumption, unexpected supply disruptions, and heightened uncertainty over the security of supply with the renewed unrest in Egypt. The U.S. Energy Information Administration (EIA) expects that the Brent crude oil spot price, which averaged $108 per barrel over the first half of 2013, will average $104 per barrel over the second half of 2013, and $100 per barrel in 2014.

- The discount of West Texas Intermediate (WTI) crude oil to Brent crude oil, which averaged $18 per barrel in 2012 and increased to a monthly average of $21 per barrel in February 2013, closed below $1.50 per barrel on July 19, 2013, and averaged $3 per barrel for the month. The strong demand for light, sweet crude oil in the Midwest and new pipeline capacity to deliver production from the West Texas Permian Basin directly to the Gulf Coast contributed to the price of WTI rising relative to Brent crude oil. EIA expects the WTI discount to widen to $6 per barrel by the end of 2013 as crude oil production in Alberta, Canada, recovers following the heavy June flooding and as midcontinent production continues to grow.

- Rising crude oil prices and seasonal demand increases contributed to U.S. regular gasoline retail prices increasing from an average of $3.50 per gallon on July 1, 2013, to $3.63 per gallon on August 5. EIA expects the regular gasoline retail price to average $3.59 per gallon in the third quarter of 2013, and the annual average price to decline from an average of $3.63 per gallon in 2012 to $3.52 per gallon in 2013 and to $3.37 per gallon in 2014.

- U.S. crude oil production increased to an average of 7.5 million barrels per day (bbl/d) in July 2013, the highest monthly level of production since 1991. EIA forecasts U.S. total crude oil production will average 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014, both about 0.1 million bbl/d higher than forecast in last month's STEO.

- Natural gas working inventories ended July 2013 at an estimated 2.88 trillion cubic feet (Tcf), about 0.37 Tcf below the level at the same time a year ago and 0.04 Tcf below the five-year average (2008-12). EIA expects the Henry Hub natural gas spot price, which averaged $2.75 per million British thermal units (MMBtu) in 2012, will average $3.71 per MMBtu in 2013 and $3.95 per MMBtu in 2014.

Global Crude Oil and Liquid Fuels

The recent increase in crude oil and liquid fuels production disruptions, which reached nearly 2.7 million bbl/d in July 2013, contributed to the recent increase in crude oil prices. During July, non-OPEC supply disruptions totaled about 800,000 bbl/d of liquid fuels, with the remaining 1.9 million bbl/d of the volume disruption occurring among OPEC producers. This level of crude oil production outages among OPEC producers is the highest since at least January 2009, and includes disruptions in Iran, Iraq, Libya, and Nigeria.

EIA estimates that global liquid fuels production outpaced consumption in the second quarter of 2013, resulting in an average global liquid fuel stock build of 260,000 bbl/d compared with an average second quarter stock draw of about 210,000 bbl/d over the previous four years. Projected global liquid fuels consumption outpaces liquid fuels production in the third quarter of 2013 with estimated global inventory withdrawal averaging 380,000 bbl/d, compared with the average withdrawal of 690,000 bbl/d during the same period over the previous four years.

Global Crude Oil and Liquid Fuels Consumption. Total world consumption increased by 390,000 bbl/d from the first quarter to the second quarter of 2013, reaching 89.5 million bbl/d. EIA projects consumption to grow by an additional 940,000 bbl/d in the third quarter of 2013, driven by seasonal consumption patterns. EIA expects annual average total world consumption to increase by 1.1 million bbl/d in 2013 and by 1.2 million bbl/d in 2014.

Non-OECD Asia, particularly China, is the leading contributor to projected global consumption growth. EIA estimates that liquid fuels consumption in China increased by 420,000 bbl/d in 2012. Projected consumption in China increases by 420,000 bbl/d in 2013 and by 440,000 bbl/d in 2014, compared with average annual growth of about 510,000 bbl/d from 2003 through 2012. Recent data indicating a weaker industrial sector and a tightening money supply in the first half of 2013 signaled slower economic growth than in prior years and, if it continues, China's oil demand growth could be lower than projected in the current STEO.

OECD liquid fuels consumption fell by 550,000 bbl/d in 2012. EIA projects that OECD consumption will decline by an additional 320,000 bbl/d in 2013 and 180,000 bbl/d in 2014, largely because of declining consumption in Europe and Japan.

Non-OPEC Supply. EIA projects non-OPEC liquid fuels production will increase by 1.3 million bbl/d in 2013 and by 1.7 million bbl/d in 2014. EIA expects non-OPEC liquid fuels production to increase by 540,000 bbl/d between the second and third quarters of 2013, and by an additional 750,000 bbl/d from the third to fourth quarters. North America accounts for most of the projected growth in non-OPEC supply over the next two years because of continued production growth from U.S. tight oil formations and Canadian oil sands.

Unplanned non-OPEC supply disruptions, which includes all liquid fuels, averaged 800,000 bbl/d in July, virtually unchanged from June. Flooding in Alberta, Canada, during June 2013 forced disruptions on a number of pipelines and production areas, and resulted in an average of 190,000 bbl/d of disrupted production volume. Although the affected pipeline resumed production in early July, production had not returned to pre-flood levels as of the end of July, as the pipeline was operating at reduced pressure throughout the month. On average, approximately 177,000 bbl/d remained disrupted in July, but production is expected to return to normal level in August.

Sudan and South Sudan, Syria, and Yemen continue to account for most of the total unplanned non-OPEC supply disruptions, however Canada's disrupted volume was the second-largest disruption in July, and second only to Syria's 250,000 bbl/d shut-in volume. South Sudan scaled back production in the second half of July, which served to offset the gains made when Canadian production returned to near-normal levels. EIA expects supply disruptions to persist in Syria and Yemen over the projection period, leading to average production of about 100,000 bbl/d in Syria and 130,000 bbl/d in Yemen over the next two years. Intensified fighting in Syria's oil-producing regions over the past several weeks makes a return to pre-conflict operating status even more unlikely in the short term. In Yemen, multiple attacks on energy infrastructure during July led to temporary production declines at the beginning and end of the month.

OPEC Supply. EIA projects total OPEC crude oil and liquids production to decline by 620,000 bbl/d in 2013 from the year before. Most of the decline in 2013 comes from Saudi Arabia in response to non-OPEC supply growth.

Persistent attacks on the Kirkuk-Ceyhan pipeline between Iraq and Turkey contributed to total disruptions in Iraq of about 290,000 bbl/d, an increase of 60,000 bbl/d from the previous month. In Libya, ongoing labor-related protests at several oil facilities have severely curtailed production for a second consecutive month. EIA estimates that Libya's crude oil production averaged 1 million bbl/d in July. Further deterioration of the security environments in Iraq and Libya could reduce OPEC production in the short term. Overall OPEC crude oil unplanned disruptions in July totaled about 1.9 million bbl/d.

EIA's estimates of current unplanned crude oil production outages among OPEC producers only represent volumes that could return on stream within one year. The estimated volumes disrupted are neither measured against nameplate production capacity nor the production volumes in the respective countries prior to the disruption. The estimated volumes rely on a determination of an effective production capacity relative to the production level, with an assessment of the difference that can return to production within one year. EIA's assessment of OPEC outages is limited to crude oil and currently includes only four countries: Iran, Iraq, Libya, and Nigeria.

EIA estimates that OPEC surplus capacity, mainly held in Saudi Arabia, averaged 2.3 million bbl/d in the second quarter of 2013. This was higher than the 2.1 million bbl/d average during the

same period last year, but lower than the average 3.6 million bbl/d from 2009 through 2011. EIA projects OPEC surplus capacity will increase to an average of 3.6 million bbl/d in the fourth quarter of 2013 and to 4.6 million bbl/d in the fourth quarter of 2014. These estimates do not include additional capacity that may be available in Iran but is currently off line because of the effects of U.S. and EU sanctions on Iran's oil sector.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories at the end of 2012 totaled 2.65 billion barrels, equivalent to 57.7 days of supply. Projected OECD oil inventories stay relatively flat in 2013, ending the year at 2.64 billion barrels. Projected inventories increase to 2.69 billion barrels (58.3 days of supply) at the end of 2014.

Crude Oil Prices. After declining to a 2013 year-to-date low of $97 per barrel on April 17, Brent crude oil spot prices increased to an average of $108 per barrel in July. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $106 per barrel and $100 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels from non-OPEC countries.

The price discount of spot WTI crude oil to Brent, which averaged $18 per barrel in 2012 and increased to a monthly average of $21 per barrel in February, narrowed to an average of $3 per barrel in July. The strong demand for light, sweet crude oil in the Midwest and new pipeline capacity delivering production from the West Texas Permian Basin directly to the Gulf Coast contributed to a draw on crude oil stocks in the Midwest and the strengthening of the price of WTI relative to Brent crude oil. EIA expects the WTI discount to begin widening again, to $6 per barrel by the end of 2013, as crude oil production in Alberta, Canada, recovers following heavy June flooding, and midcontinent crude oil production growth outpaces increases in capacity to transport crude oil from the region to refining centers on the Gulf and East Coasts. After averaging $94 per barrel in 2012 and increasing to $105 per barrel in July 2013, the forecast WTI crude oil spot price averages $97 per barrel in 2013 and $93 per barrel in 2014. By 2014, several pipeline projects from the midcontinent to the Gulf Coast refining centers are expected to come on line, reducing the cost of transporting crude oil to refiners, which is reflected in a narrowing in the WTI price discount to Brent next year.

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 November 2013 delivery traded during the five-day period ending August 1, 2013, averaged $103 per barrel. Implied volatility averaged 21 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in September 2013 at $85 per barrel and $125 per barrel, respectively. Last year at this time, WTI for November 2012 delivery averaged $89 per barrel and implied volatility averaged 32 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $67 per barrel and $119 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. regular gasoline retail prices increased from an average of $3.50 per gallon to $3.68 per gallon over the first three weeks of July. Prices have declined over the past two weeks, reaching $3.63 per gallon on August 5. Isolated refinery outages and regional disruptions have contributed to greater volatility in regional gasoline prices across the United States this year. Some of the greatest volatility was again seen across the Midwest. EIA expects gasoline prices to slowly fall from their mid-July levels as crude oil prices begin to fall and the summer driving season comes to a close.

U.S. Liquid Fuels Consumption. In 2012, total liquid fuels consumption declined by 395,000 bbl/d (2.1 percent). Total liquid fuels consumption for the first half of 2013 rose an estimated 120,000 bbl/d (0.6 percent) compared with the same period last year, led by increases in liquefied petroleum gas and distillate consumption. Projected total liquids consumption during the second half of 2013 increases by 150,000 bbl/d from the same period last year, with distillate fuel accounting for most of the growth.

Preliminary estimates of gasoline consumption during July 2013 showed relatively strong growth over the same month last year. However, EIA continues to expect flat to declining gasoline consumption as improving fuel economy of new vehicles continues to outpace growth in highway travel.

U.S. Liquid Fuels Supply. EIA expects U.S. crude oil production to rise from an average of 6.5 million bbl/d in 2012 to 7.4 million bbl/d in 2013 and 8.2 million bbl/d in 2014. The continued focus on drilling in tight oil plays in the onshore Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years. Offshore production from the Gulf of Mexico is forecast to average 1.3 million bbl/d in 2013 and 1.4 million bbl/d in 2014.

Since reaching 12.5 million bbl/d in 2005, total U.S. liquid fuel net imports, including crude oil and petroleum products, have been falling. Total net imports fell to 7.4 million bbl/d in 2012, and EIA expects net imports to continue declining to an average of 5.6 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012. EIA expects the net import share to continue to fall to 30 percent in 2014, which would be the lowest level since 1985.

U.S. Petroleum Product Prices. EIA expects that regular-grade gasoline retail prices, which averaged $3.59 per gallon during the first half of 2013, will average $3.59 per gallon and $3.33 per gallon during the third and fourth quarters of 2013, respectively. Led by falling crude oil prices, the projected U.S. average regular gasoline retail price falls from $3.63 per gallon in 2012 to an average $3.52 per gallon in 2013 and $3.37 per gallon in 2014. Diesel fuel prices, which averaged $3.97 per gallon in 2012, are projected to average $3.92 per gallon in 2013 and $3.76 per gallon in 2014.

The current values of futures and options contracts suggest that gasoline prices could differ significantly from this forecast. For example, there is a 4-percent probability that the New York Harbor reformulated gasoline blendstock for oxygenate blending (RBOB) futures price will exceed $3.35 per gallon (consistent with a U.S. average regular gasoline retail price above $4.00 per gallon) in November 2013.

Natural Gas

A heat wave in the Northeast in mid-July contributed to spikes in the price of wholesale natural gas and electric power, as well as near-record consumption of natural gas for power generation in the Northeast. Although recent pipeline capacity additions have helped ease movement of natural gas supplies in the area, constraints continue to limit gas flow to the region, particularly in times of high demand. The day-ahead price of natural gas at the Algonquin Citygate, which serves Boston consumers, rose to $8.09 per million British thermal units (MMBtu) at the end of trading on July 16. This was its highest level since March 2013, and more than $4 per MMBtu greater than the benchmark Henry Hub price ($3.69 per MMBtu) in Louisiana. Additionally, on New York's independent system operator's trading platform, real-time hourly wholesale power prices spiked to more than $800 per megawatt hour on July 17.

U.S. Natural Gas Consumption. EIA expects that natural gas consumption, which averaged 69.7 Bcf/d in 2012, will average 69.9 Bcf/d and 69.3 Bcf/d in 2013 and 2014, respectively. Colder winter temperatures in 2013 and 2014 (compared with the record-warm temperatures in 2012) are expected to increase the amount of natural gas used for residential and commercial space heating. However, the projected year-over-year increases in natural gas prices contribute to declines in natural gas used for electric power generation from 25.0 Bcf/d in 2012 to 22.2 Bcf/d in 2013 and 21.6 Bcf/d in 2014.

U.S. Natural Gas Production and Trade. Natural gas marketed production is projected to increase from 69.2 Bcf/d in 2012 to 69.9 Bcf/d in 2013 and to 70.5 Bcf/d in 2014. Onshore production increases over the forecast period, while federal Gulf of Mexico production from existing fields declines as the economics of onshore drilling remain more favorable. Natural gas pipeline gross imports, which have fallen over the past five years, are projected to fall by 0.2 Bcf/d in 2013 and then remain near 2013 levels in 2014. LNG imports are expected to remain at minimal levels of around 0.4 Bcf/d in both 2013 and 2014.

U.S. Natural Gas Inventories. As of July 26, 2013, working gas stocks totaled 2,845 Bcf, which is 368 Bcf less than at the same time last year, but only 34 Bcf below the five-year (2008-12) average for that week. EIA projects working gas stocks at the end of this summer's stock-build season (end of October) will reach 3,800 Bcf, about 130 Bcf below the level at the same time last year.

Working gas storage capacity grew by about 2 percent in 2012, according to EIA's most recent report on maximum capacity in the Lower 48 states. EIA has two measures of the volume of working natural gas that can be stored in underground facilities for future use—demonstrated maximum and design capacity—and both increased by about 2 percent from November 2011 to November 2012. The producing region accounted for the largest increases in capacity.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.62 per MMBtu at the Henry Hub in July 2013, down 21 cents from the previous month's price. EIA expects the Henry Hub price will increase from an average of $2.75 per MMBtu in 2012 to $3.71 per MMBtu in 2013 and $3.95 per MMBtu in 2014. Despite declines in prices over the past few months, prices still remain substantially above their year-ago levels. (Henry Hub prices last July averaged $2.95 per MMBtu, and the average spot prices at most other major trading hubs over the first 6 months of 2013 increased by 40 percent to 60 percent from the same period last year.)

Natural gas futures prices for November 2013 delivery (for the five-day period ending August 1, 2013) averaged $3.58 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for November 2013 contracts at $2.68 per MMBtu and $4.79 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for November 2012 averaged $3.26 per MMBtu and the corresponding lower and upper limits of the 95-percent confidence interval were $2.13 per MMBtu and $4.98 per MMBtu.

Coal

While coal market fundamentals changed in first-half 2013 compared with the same period of 2012, spot prices remained largely unchanged. Demand for coal was higher and production was lower in first-half 2013, but because electric companies chose to burn off large inventories instead of buying more coal and because international coal prices were weaker, the spot market price remained largely unchanged. EIA expects declines in exports and stocks to moderate during the second half of 2013 as the first year-over-year increases in quarterly coal consumption since 2010 continue.

U.S. Coal Consumption. EIA estimates that total coal consumption for the first half of 2013 was 448 million short tons (MMst), or 38 MMst (9.4 percent) higher than the amount of coal consumed in the first six months of 2012. The increase was primarily a result of consumption growth in the electric power sector because of higher electricity demand and higher natural gas prices. EIA expects that this trend will continue in the second half of 2013 with total coal consumption for the year of 952 MMst (a 6.9-percent increase over 2012). Consumption grows at a more modest pace of 1.4 percent to 966 MMst in 2014.

U.S. Coal Supply. Coal production in the first half of 2013 was 21 million tons, or 4 percent, lower than in the same period of 2012. The largest declines were in the Appalachian (13.6 MMst) and Western (8.1 MMst) regions. Interior region production was similar to last year. EIA

projects higher production in all regions during the second half of 2013 compared with the same period last year, with total coal production of 1,016 MMst in 2013, unchanged from last year. Coal production is forecast to grow by 3.3 percent in 2014 to 1,050 MMst as inventories stabilize and consumption increases.

Inventory draws are expected to meet most of the growth in consumption in 2013. Estimates of total coal inventories ended the first half of 2013 at 28 MMst lower than the same time last year. EIA forecasts an additional 9 MMst of inventory withdrawals over the second half of 2013.

U.S. Coal Exports. EIA estimates that first half 2013 exports totaled 61.2 MMst, which was 5.0 MMst lower than the same period last year despite record monthly exports of 13.6 MMst in March. Exports for the next six months are expected to continue declining, with second-half exports totaling 53 MMst, down 7 MMst from last year. Exports are projected to total 108 MMst in 2014. Continuing economic weakness in Europe (the largest regional importer of U.S. coal), slowing Asian demand growth, increasing supply 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. Delivered coal prices (to the electric power industry) were down an estimated 2.5 percent ($0.06 per MMBtu) for the first six months of 2013 compared with the same period last year. EIA expects nominal annual average coal prices to the electric power industry to fall for the first time since 2000, from $2.40 per MMBtu in 2012 to $2.37 MMBtu in 2013. EIA forecasts average delivered coal prices of $2.40 per MMBtu in 2014.

Electricity

The northeastern United States experienced a strong heat wave during mid-July. In response, many customers ran their air conditioners more than usual. EIA estimates the average residential customer in New England will use about 1.0 percent more electricity during the summer of 2013 (June-August) compared with last summer, while customers in the Middle Atlantic states are expected to use about 0.5 percent less electricity. In addition to increased electricity demand, the heat wave also caused temporary spikes in wholesale power prices. State retail rate regulations shield many residential customers from price swings in the wholesale power market, but EIA expects summer electricity prices in the Northeast to average about 2.7 percent higher than summer 2012, primarily as a result of higher fuel costs paid by generators.

U.S. Electricity Consumption. Despite last month's heat wave in the Northeast, summer temperatures in other areas of the United States are cooler than last year, especially in the Midwest Census region where cooling degree days between June and August total 23 percent less than last summer. For the entire year, forecast U.S. retail sales of electricity to the residential sector during 2013 average 1.3 percent more than 2012, as lower summer consumption is offset by higher consumption during the non-summer months. Forecast retail

sales of electricity to the commercial sector grow by 0.5 percent in 2013, while industrial sector retail electricity sales fall by 0.5 percent.

U.S. Electricity Generation. EIA expects total U.S. electricity generation will grow by 0.5 percent in 2013 and by 0.4 percent in 2014. Electric generators have been running their existing coal capacity at higher rates so far this year in response to the increasing cost of natural gas relative to coal. During the first half of 2013, EIA estimates generation fueled by coal averaged 4,250 gigawatthours per day (GWh/d), corresponding to a 39.2 percent share of total generation. In contrast, coal's share of total generation during the first half of 2012 was 35.4 percent (3,810 GWh/d). Coal's recent gains in fuel share are expected to slow during the second half of 2013 when coal's projected share of total generation averages 41.4 percent compared with 39.3 percent in second half of 2012. Natural gas accounted for 30.4 percent of total generation during 2012, but EIA expects this share to fall to an average of 27.4 percent during 2013.

U.S. Electricity Retail Prices. Generation fuel costs and wholesale electricity prices have increased this year after a considerable decline in 2012. During the first half of 2013, EIA estimates the price of natural gas delivered to electric generators averaged $4.46 per MMBtu, 44 percent higher than the same period last year. Changes in the costs of providing electricity are not immediately reflected on retail customer bills because state regulatory commissions must approve rate changes in many areas of the country. EIA expects the residential retail price of electricity in 2013 will average 12.1 cents per kilowatthour, about 1.9 percent higher than the price last year.

Renewables and Carbon Dioxide Emissions

U.S. Electricity and Heat Generation from Renewables. EIA projects renewable energy consumption for electricity and heat generation to increase by 3.4 percent in 2013. While hydropower declines by 4.2 percent, nonhydropower renewables used for electricity and heat generation grow by an average of 8.1 percent in 2013. In 2014, the growth in renewables consumption for electric power and heat generation is projected to continue at a rate of 4.2 percent, as a 3.1-percent increase in hydropower is combined with a 4.9-percent increase in nonhydropower renewables.

EIA estimates that wind capacity will increase by 5 percent this year to about 62 gigawatts, and reach over 72 gigawatts in 2014. However, electricity generation from wind is projected to increase by 19 percent in 2013, as capacity that came on line at the end of 2012 is available for the entire year in 2013. Wind-powered generation is projected to grow by 7 percent in 2014.

EIA expects continued robust growth in the generation of solar energy, although the amount of utility-scale generation remains a small share of total U.S. generation, about 0.2 percent in 2013. Utility-scale capacity, which until recently experienced little growth compared with customer-sited distributed generation capacity, is projected to more than double between 2012 and 2014. Photovoltaics (PV) accounted for all utility-scale solar growth in 2012, but EIA expects that

several large solar thermal generation projects will enter service in 2013 and 2014. However, PV is still expected to account for most of the capacity additions in 2013 and 2014. Solar generation by the electric power sector increases 80 percent in 2013 and 55 percent in 2014.

U.S. Liquid Biofuels. Smaller corn harvests due to widespread drought resulted in U.S. fuel ethanol production falling from an average of approximately 900,000 bbl/d (13.9 billion gallons per year) in the first half of 2012 to an average of 820,000 bbl/d (12.6 billion gallons per year) from July 2012 through March 2013. Forecast ethanol production increases to an average 920,000 bbl/d in 2014, driven in part by increasing Renewable Fuel Standard (RFS) targets and strong demand for Renewable Identification Numbers (RINs). Biodiesel production, which averaged 63,000 bbl/d (1.0 billion gallons per year) in 2012, has been rising this year and reached a record level of 111 million gallons (85,000 bbl/d) in May 2013. Biodiesel production is forecast to average about 82,000 bbl/d in 2013 and 88,000 bbl/d in 2014. This forecast assumes that the 2014 renewable fuel standards are identical to those proposed for 2013.

The U.S. Environmental Protection Agency (EPA) proposed rule for the 2013 RFS program year maintains the statutory target of 16.55 billion ethanol-equivalent gallons of total renewable fuels. It would require refiners and importers of gasoline and diesel fuel to deliver RINs equivalent to the 2013 renewable volume obligation (RVO) of 9.63 percent of the gasoline or diesel fuel they sell domestically (not counting the biofuels blended into it). The market price of corn ethanol (D6 classification) RINs increased dramatically during the first quarter of 2013, from $0.05 per gallon at the start of the year to as high as $1.05 per gallon on March 11. After weeks of hovering around $0.80 per gallon, D6 RIN prices once again rose sharply in July, reaching new daily highs over $1.40 per gallon, before returning to near the $1.00 level at the end of month.

The increase in the ethanol RIN price provides an economic incentive for two changes in the market. First, a higher ethanol RIN price tends to lower the market price of E85 gasoline relative to E10 gasoline. Second, an ethanol RIN price equal to or near the biodiesel RIN price may motivate blending of biodiesel in excess of the biodiesel blending target that EPA announced in the 2013 RFS program.

At the retail level, EIA expects diesel fuel prices to be most affected by higher RIN prices as typical biodiesel blending yields only about one-third of the RINs required and diesel fuel refiners and blenders must make up for the shortfall by purchasing the now higher-priced RINs.

U.S. Energy-Related Carbon Dioxide Emissions. EIA estimates that carbon dioxide emissions from fossil fuels declined by 3.9 percent in 2012, and projects increases of 2.4 percent in 2013 and 0.3 percent in 2014. The increase in emissions over the forecast period primarily reflects the projected increase in coal use for electricity generation, especially in 2013 as it rebounds from the 2012 decline.

U.S. Economic Assumptions

EIA uses the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO. The GI simulation used in this STEO assumes that the spending cuts mandated in the Budget Control Act of 2011 (sequestration) are replaced by a combination of changes of tax and spending changes that are implemented in 2014. In addition, GI assumes there will be an agreement reached to increase the amount of debt that can be issued by the U.S. Treasury.

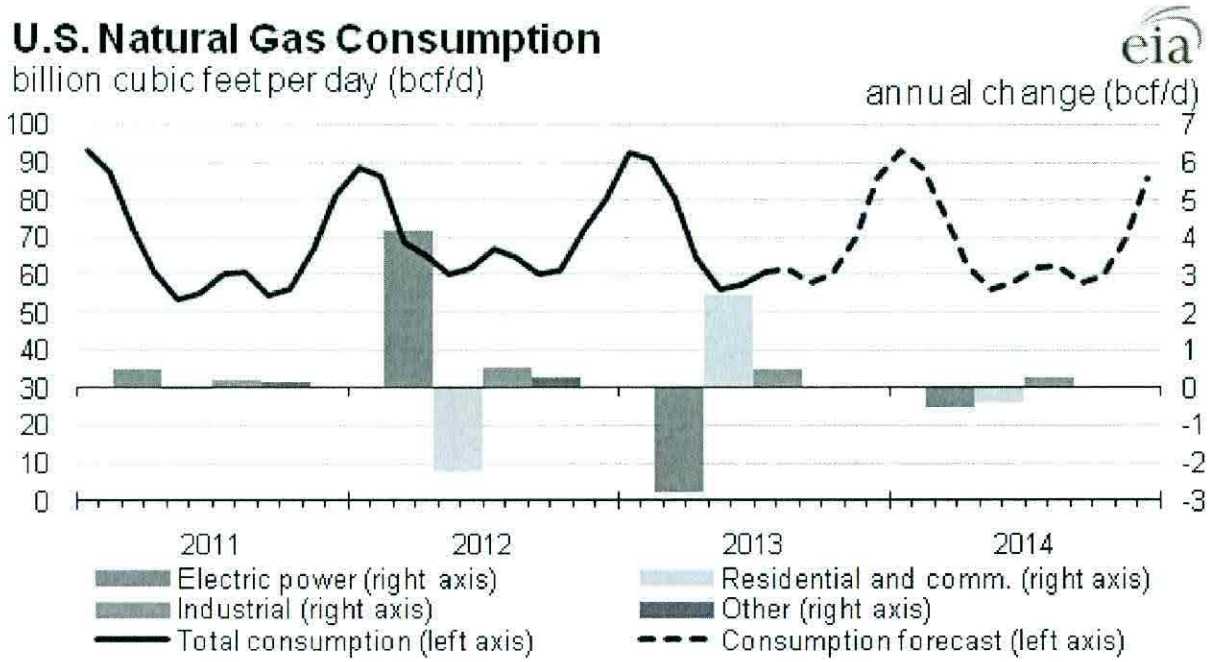
U.S. Current Trends. The U.S. Census Bureau reported that new orders for manufactured durable goods rose 4.2 percent in June, following a revised 5.2-percent increase in May. But the June increase falls to 0.1 percent when orders for defense and aircraft are excluded. The U.S. Commerce Department also reported that sales of new single-family homes increased by over 38 percent from June 2012 to June 2013, and 8.3 percent from May 2013 to June 2013. The Federal Reserve Bank of Philadelphia's survey of business conditions improved from June to July, but a more inclusive measure that includes inventories, orders, and shipments is barely in expansion territory at 51.1 (values above 50 indicate expansion). In addition, the Federal Reserve Board reported that total U.S. industrial production gained 0.3 percent from May to June 2013 and capacity utilization was up 0.1 percent over the same time period.

U.S. Production and Income. The STEO assumes 1.6-percent real U.S. GDP growth in 2013, rising to 2.6 percent in 2014. Year-on-year real GDP growth begins to accelerate in the second half of 2014, eventually rising to 3.1 percent in the fourth quarter of 2014. Forecast real disposable income increases 0.5 percent in 2013 and 3.4 percent in 2014. Total industrial production grows almost one percentage point faster than real GDP in 2013 at 2.5 percent, and its projected growth of 3.2 percent in 2014 is still well above the growth rate of real GDP.

U.S. Expenditures. Private fixed investment growth averages 6.0 and 7.9 percent over 2013 and 2014, respectively, down from the 6.1 and 8.6 percent projected last month. Real consumption expenditures grow faster than real GDP in 2013, at 1.9 percent, but slow below the rate of real GDP growth in 2014, at 2.3 percent. Export growth triples from 1.7 to 5.1 percent over the same two years. Government expenditures fall 3.0 percent in 2013, and rise by 0.2 percent in 2014.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast averages 7.6 percent over 2013, and gradually falls to 7.1 percent at the end of 2014. This is accompanied by nonfarm employment growth averaging 1.6 percent in 2013 and 1.5 percent in 2014. Consistent with an improving housing sector, housing starts grow an average of 22.6 percent and 26.8 percent in 2013 and 2014, respectively. Both consumer and producer price indexes continue to increase at a moderate pace.

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

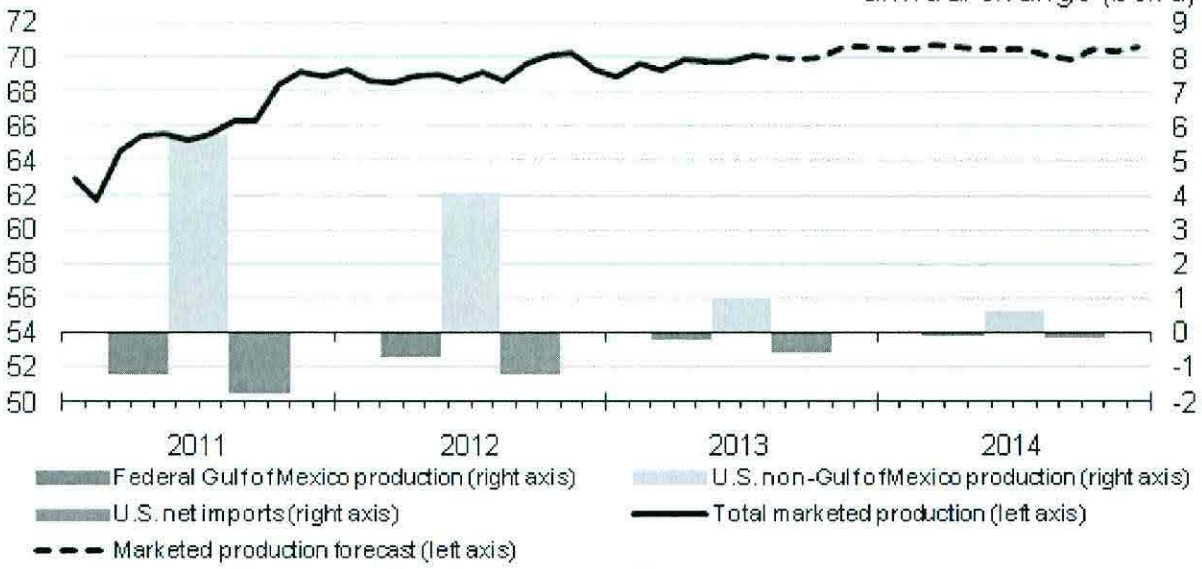


Source: Short-Term Energy Outlook, August 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d)

annual change (bcf/d)



Federal Gulf of Mexico production (right axis)

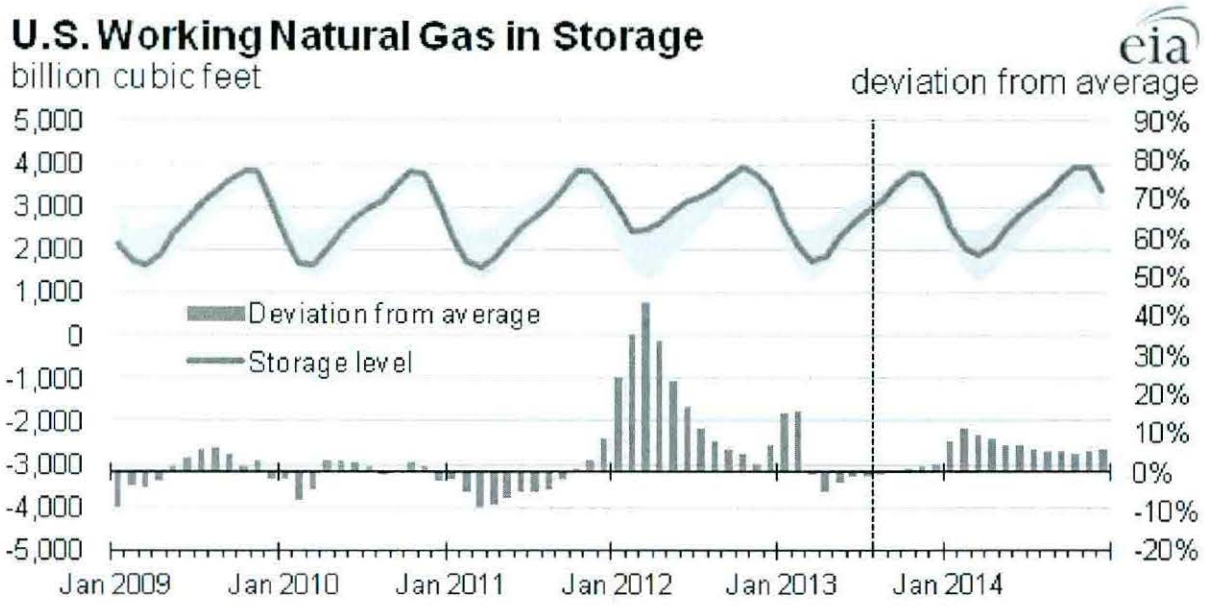
U.S. non-Gulf of Mexico production (right axis)

U.S. net imports (right axis)

Total marketed production (left axis)

Marketed production forecast (left axis)

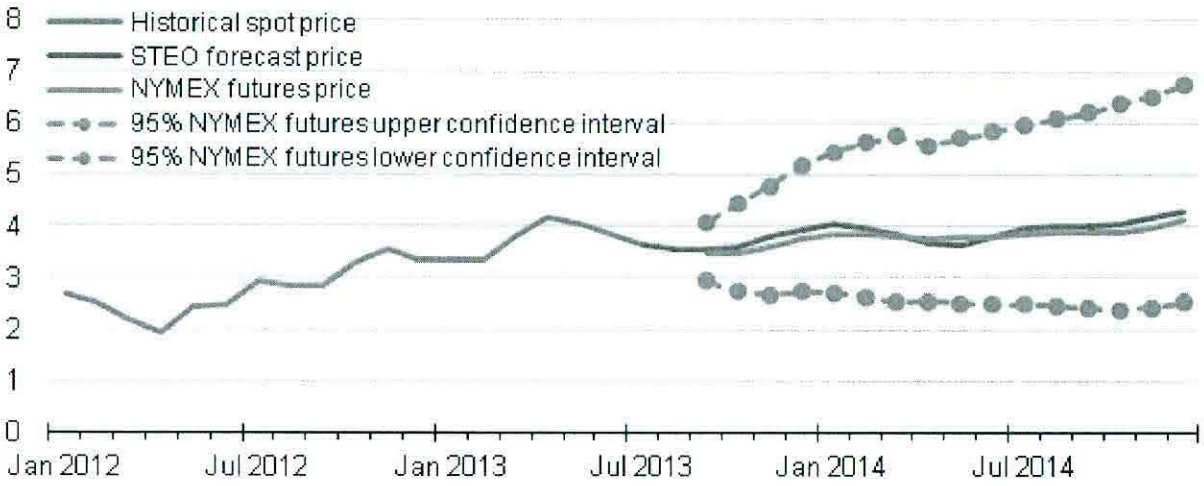
Source: Short-Term Energy Outlook, August 2013



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.
Source: Short-Term Energy Outlook, August 2013

Henry Hub Natural Gas Price

dollars per million btu

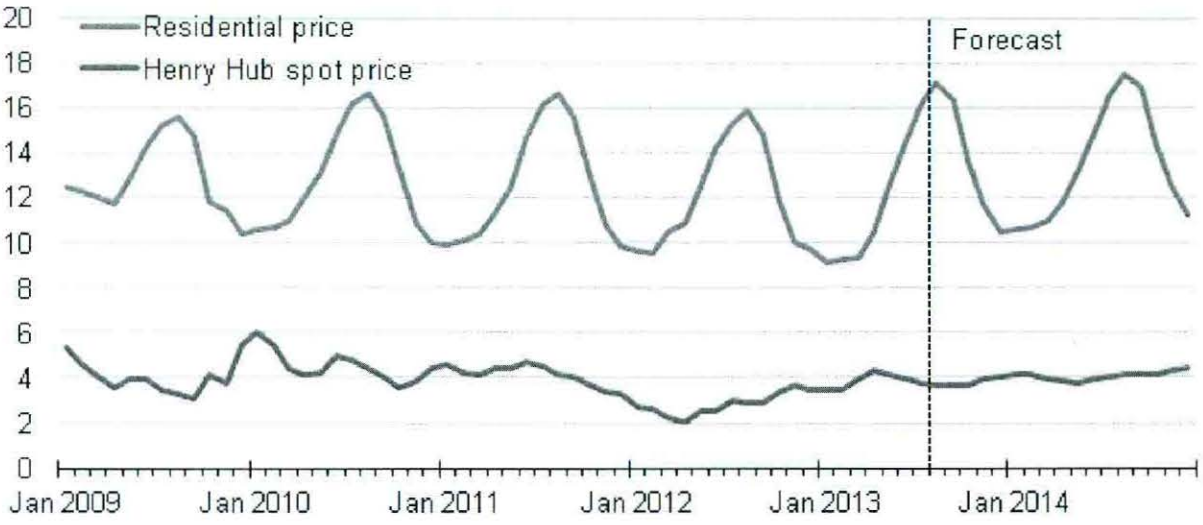


Note: Confidence interval derived from options market information for the 5 trading days ending August 1, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, August 2013

U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, August 2013

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	($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
Total	$11,379	0	$5,087	$16,466	36,618		$36,631	($20,165)	
Balance @ July 31, 2013									**$283,146**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 5,911.4 dk @ $1.0137 and 3,302.1 dk @ $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	($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)
Total	($42,040)	0	($165)	($42,205)	91,017		($18,269)	($23,936)	
Balance @ July 31, 2013									**($19,189)**

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