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

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PO Box 176
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1-877-267-4764

February 1, 2013

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

Re: Cost of Gas Adjustment (COG)
February 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 (83rd Revised Sheet No. 1.1) showing the proposed natural gas rates and the Cost of Gas Tariff (83rd Revised Sheet No. 8), showing the February 2013 cost of gas and the resulting Cost of Gas Adjustment. The net effect of this filing is an increase of $0.0450 per mcf for all customers.

Attachment B shows the calculations supporting the gas costs for February 2013, including the calculation of the commodity cost of gas. The commodity cost of gas has increased $0.0450 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, 2012.

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

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
83rd Revised Sheet No. 1.1
Canceling 82nd 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	$6.1460	$7.4200
			Over 10 MCF	1.0540		7.2000
Firm Gas Service - General Highway 13	2.5	$3.50 per month	First 10 MCF	$2.1740	$6.1460	$8.3200
			Over 10 MCF	1.9540		8.1000
Interruptible Gas Service - General	3	$3.50 per month	First 400 MCF	$1.1391	$3.3147	$4.4538
			Next 2,600 MCF	0.8931		4.2078
			Over 3,000 MCF	0.7411		4.0558
Interruptible Gas Service - Highway 13	3.5	$3.50 per month	First 400 MCF	$2.0391	$3.3147	$5.3538
			Next 2,600 MCF	1.7931		5.1078
			Over 3,000 MCF	1.6411		4.9558
Interruptible Gas Service - Grain Processing	4	$3.50 per month	All MCF	$1.2391	$3.3147	$4.5538
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: February 1, 2013

Effective Date: Service rendered on and after February 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
83rd Revised Sheet No. 8
Canceling 82nd 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.	1.4751	(1.5727)	1.0137	0.9161	(1.5579)	(0.2915)	(1.8494)
Current Adj.	0.0000	0.0450	0.0000	0.0450	0.0450	0.0000	0.0450
Total Adj.	1.4751	(1.5277)	1.0137	0.9611	(1.5129)	(0.2915)	(1.8044)
Total Rate:	$1.5409	$3.5914	$1.0137	$6.1460	$3.6062	($0.2915)	$3.3147

Date Filed: February 1, 2013

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

Issued By: Tamie A. Aberle
Director - Regulatory Affairs

Case No.:

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

Firm	Billing Determinants		Rate	Demand Months	Amount	Amount Per dk
FT-A	8,000		$3.4671	12	$332,842	$0.2378
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	0.0737
FT-A Seasonal	2,000		3.7671	5	37,671	0.0269
TFX Seasonal	2,000		15.1530	5	151,530	0.1083
TFX - Winter	13,000		15.1530	5	984,945	0.7037
TFX - Summer	13,000		5.6830	7	517,153	0.3695
LMS Demand 2/						0.0148
Total Demand Charges					$2,136,019	1.5409
Estimated Weighted Average Commodity Cost	1,399,684	1/	3.5914		5,026,825	3.5914
Gas Cost Reconciliation Adjustment						1.0137
Total Current Firm Gas Cost					$7,162,844	6.1460
Base Cost of Gas						5.1849
Accumulated Adjustment						$0.9611

Interruptible	
Estimated Weighted Average Commodity Cost	$3.5914
Gas Cost Reconciliation Adjustment	(0.2915)
LMS Demand 2/	0.0148
Total Current Interruptible Gas Cost	3.3147
Base Cost of Gas	5.1191
Accumulated Adjustment	($1.8044)

1/ Three year normalized average Dk sales.
2/ Amount divided by 2008-2010 average interruptible sales volumes plus 2008-2010 average normalized firm sales volumes.

	Billing Determinants	Rate	Demand Months	Amount	Amount Per dk
LMS Demand	2,500	$1.0000	12	$30,000	$0.0148

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

Rates Effective November 1, 2012	$/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:	3.5914	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

Rate Schedule	Base Tariff Rate
Category 1 (Contract Term of Less than 3 Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$0.1238
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$0.1607
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$0.0704
Zone 2-2 Minimum Rate	$0.0000
Category 2 (Contract Term of 3 Years to less than 5 Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$0.1189
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$0.1557
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$0.0654
Zone 2-2 Minimum Rate	$0.0000
Category 3 (Contract Term of 5 or more Years)	
Daily Reservation Rates	
FT-A	
Zone 1-1 Maximum Rate	$0.1140
Zone 1-1 Minimum Rate	$0.0000
Zone 1-2 Maximum Rate	$0.1508
Zone 1-2 Minimum Rate	$0.0000
Zone 2-2 Maximum Rate	$0.0605
Zone 2-2 Minimum Rate	$0.0000

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	0.76%
Zone 1-2	$0.0130	$0.0018	$0.0148	0.86%
Zone 2-2	$0.0130	$0.0018	$0.0148	0.10%
Minimum Rate	$0.0130	$0.0018	$0.0148	
IT and AOT				
Zone 1-1	$0.1368	$0.0018	$0.1386	0.76%
Zone 1-2	$0.1737	$0.0018	$0.1755	0.86%
Zone 2-2	$0.0834	$0.0018	$0.0852	0.10%
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: 0.15% for Zone 1-1, 0.17 % 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		($0.0022)	

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/ 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	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	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 $0.0001 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	0.0378	0.0209			0.0175	0.0000	0.0378	0.0209
Field	Market	0.0378	0.0209	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 $0.0001 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)	0.97%
Field Area	2/ 3/ 5/ 6/
UNACCOUNTED FOR PERCENTAGE (including Out-of-Balance)	0.43% 4/ 5/
FDD Storage Fuel	1.09%

	Electric Compression
COMMODITY RATES:	1/
Market Area	$0.0001
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, 2011.

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
February 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 much of this gas is the Northern Natural Gas Co. Ventura, Iowa point which is an actively traded market point in North America. The February 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.

National storage levels remain higher than the five year average and national temperatures cycling between colder than normal and near record highs for this time of the year likely contributed to the NNG-Ventura index price remaining in the same range as the previous month. The northeast, which has pipeline capacity constraints, experienced some large swings in the daily price of natural gas but the price swings were not experienced across the rest of the nation. The Energy Information Administration (EIA) reported storage levels nationwide as of January 25, 2013 were 12.2 percent above the five-year average and 6.7 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

January 2013

Short-Term Energy Outlook (STEO)

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2014.

- EIA expects that the Brent crude oil spot price, which averaged $112 per barrel in 2012, will fall to an average of $105 per barrel in 2013 and $99 per barrel in 2014. The projected discount of West Texas Intermediate (WTI) crude oil to Brent, which averaged $18 per barrel in 2012, falls to an average of $16 per barrel in 2013 and $8 per barrel in 2014, as planned new pipeline capacity lowers the cost of moving Mid-continent crude oil to the Gulf Coast refining centers.

- EIA expects that falling crude prices will help national average regular gasoline retail prices fall from an average $3.63 per gallon in 2012 to annual averages of $3.44 per gallon and $3.34 per gallon in 2013 and 2014, respectively. Diesel fuel retail prices averaged $3.97 per gallon during 2012 and are forecasted to fall to an average of $3.87 per gallon in 2013 and $3.78 per gallon in 2014.

- EIA estimates U.S. total crude oil production averaged 6.4 million barrels per day (bbl/d) in 2012, an increase of 0.8 million bbl/d from the previous year. Projected domestic crude oil production continues to increase to 7.3 million bbl/d in 2013 and 7.9 million bbl/d in 2014, which would mark the highest annual average level of production since 1988.

- Total U.S. liquid fuels consumption fell from an average 20.8 million bbl/d in 2005 to 18.6 million bbl/d in 2012. EIA expects total consumption to rise slowly over the next two years to an average 18.8 million bbl/d in 2014, driven by increases in distillate and liquefied petroleum gas consumption, with flat gasoline and jet fuel consumption.

- Natural gas working inventories, which a record-high level in early November, ended 2012 at an estimated 3.5 trillion cubic feet (Tcf), slightly above the level at the same time the previous year. EIA expects the Henry Hub natural gas spot price, which averaged $4.00 per million British thermal units (MMBtu) in 2011 and $2.75 per million MMBtu in 2012, will average $3.74 per MMBtu in 2013 and $3.90 per MMBtu in 2014.

- EIA expects the coal share of total electricity generation to rise from 37.6 percent in 2012 to 39.0 percent in 2013 and 39.6 percent in 2014, as natural gas prices rise relative to coal prices. Lower-than-projected natural gas prices along with the industry's response to future environmental regulations could cause the coal share of total generation to fall below this forecast.

Global Crude Oil and Liquid Fuels

Global Crude Oil and Liquid Fuels Overview. EIA expects oil markets to loosen in 2013 and 2014 as increasing global supply more than offsets higher global consumption. Projected world supply increases by 1.0 million bbl/d in 2013 and 1.7 million bbl/d in 2014, with most of the growth coming from outside the Organization of the Petroleum Exporting Countries (OPEC). North America will account for much of this growth. Projected world liquid fuels consumption grows by an annual average of 0.9 million barrels per day (bbl/d) in 2013 and 1.3 million bbl/d in 2014. Countries outside the Organization for Economic Cooperation and Development (OECD) drive expected consumption growth.

Global Crude Oil and Liquid Fuels Consumption. World liquid fuels consumption grew by an estimated 0.9 million bbl/d in 2012 to reach 89.2 million bbl/d. EIA expects that this growth will remain about the same over the next year before picking up again in 2014 due to a moderate recovery in global economic growth; consumption reaches 90.1 million bbl/d in 2013 and 91.5 million bbl/d in 2014. Non-OECD Asia is the leading regional contributor to expected global consumption growth.

OECD liquid fuels consumption declined by 0.4 million bbl/d in 2012. EIA projects OECD consumption to further decline by 0.3 million bbl/d in 2013, as modest consumption growth in North America is more than offset by decreasing consumption in Europe. The OECD consumption decline narrows to 0.1 million bbl/d in 2014 as European consumption begins to flatten in response to higher economic growth. EIA projections do not assume any significant deterioration of the economic situation in the United States or the European Union (EU) next year.

Non-OPEC Supply. Although supply growth in the United States and Russia during 2012 outpaced our forecast at the beginning of the year, overall non-OPEC liquid fuels production fell below the year-ago expectations. EIA forecasts non-OPEC production to increase by 1.4 million bbl/d in 2013 and 1.3 million bbl/d in 2014, but assumptions about the mitigation of some of the current political impediments to production and the rapid evolution of the North American oil industry introduce considerable risks to the forecast. North America accounts for about two-thirds 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 production outages in non-OPEC countries declined to 0.8 million bbl/d in December 2012, the lowest level since January 2012, but still above the historical baseline that prevailed during the fourth quarter of 2011. Syria and the Sudans are currently the most significant sources of disruption to non-OPEC production. EIA does not assume a resolution in Syria will occur during the forecast period. Sudan and South Sudan must still overcome political and technical obstacles before significant flows from the latter can be restarted. EIA projects that

Sudan and South Sudan combined will produce 0.2 million bbl/d in 2013 and 0.4 million bbl/d in 2014.

OPEC Supply. EIA expects that OPEC members will continue to produce at least 30 million bbl/d of crude oil over the next two years to accommodate the projected increase in world oil consumption and to counterbalance supply disruptions. However, OPEC crude supply decreases by 0.6 million bbl/d in 2013 and stays flat through 2014. Most of the decrease in 2013 comes from Saudi Arabia, which responds to non-OPEC growth and increasing production from some OPEC members, such as Iraq, Nigeria, and Angola.

Libyan oil production increased considerably over the last year to a level approaching pre-crisis capacity. Yet various small disruptions to Libyan production, refining, and exports over the last few months reinforce EIA's previous assessments of the continuing risks to the Libyan oil industry. We expect output to fluctuate around current levels until a permanent government is successfully installed.

Iraq has increased production by 0.4 million bbl/d since last year, in part due to new export infrastructure in the southern part of the country. However, heightened tensions between the central government, Kurdish Regional Government, and some Sunni and Shia factions could undermine the continued growth of its oil production over the near term.

Despite new output from deepwater fields, Nigeria's production declined slightly in 2012 from the previous year as increased oil theft and flooding cut crude oil production in the fourth quarter to 2.0 million bbl/d. Barring any major unforeseen supply disruptions, EIA projects Nigerian production to increase in 2013 and 2014 as output from deepwater fields ramps up and new fields are brought online. For more on upcoming oil projects in Nigeria, see EIA's country analysis brief.

Technical and maintenance problems have plagued some of Angola's deepwater fields for years, particularly the Greater Plutonio Project, and will continue to limit Angola's crude oil production over the forecast period. The country's oil minister recently expressed skepticism over Angola's ability to reach its target of 2 million bbl/d in 2013. EIA's projection reflects that same skepticism, since several technical field problems remain unresolved. Nonetheless, EIA still anticipates Angolan crude oil output to gradually increase over the next two years as new deepwater production more than offsets chronic maintenance-related declines.

EIA estimates that liquid fuels production and consumption in Iran averaged 3.2 million bbl/d and 1.7 million bbl/d, respectively, during November and December 2012. Iranian crude oil production had been falling since at least the last quarter of 2011, due to the country's inability to carry out investment projects that are necessary to offset the natural decline in production from existing wells, while the latest round of U.S. and EU sanctions contributed to steeper declines in Iranian exports and production during the second and third quarters of 2012. However, this tentative interpretation of a very fluid situation could change as EIA revises data,

industry sources issue independent estimates of Iranian production, and more details about Iranian storage levels, refinery utilization, and domestic consumption emerge.

EIA estimates that OPEC surplus capacity, which is overwhelmingly concentrated in Saudi Arabia, remained relatively tight by historical standards at around 2.3 million bbl/d in December 2012. Projected OPEC surplus capacity increases to 3.1 million bbl/d in 2013. This estimate does not include additional capacity that may be available in Iran but which is currently offline due to the impacts of U.S. and EU sanctions on Iran's ability to sell its oil.

OECD Petroleum Inventories. EIA estimates that OECD commercial oil inventories ended 2012 at 2.67 billion barrels, equivalent to 58 days of supply. Projected OECD oil inventories remain relatively flat throughout the next year and end 2013 at 2.66 billion barrels (58 days of supply). Inventories grow to 2.69 billion barrels (59 days of supply) by the end of 2014.

Crude Oil Prices. EIA projects the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $105 per barrel and $99 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels by non-OPEC countries. After averaging $94 in 2012, the WTI price will average $90 per barrel in 2013 before increasing to an average of $91 per barrel in 2014. By 2014, several pipeline projects from the Mid-continent 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 declining discount of WTI to Brent over the forecast period.

Energy price forecasts are highly uncertain (*Market Prices and Uncertainty Report*). WTI futures for April 2013 delivery during the five-day period ending January 3, 2013, averaged $92.84 per barrel. Implied volatility averaged 26 percent, establishing the lower and upper limits of the 95-percent confidence interval for the market's expectations of monthly average WTI prices in April 2013 at $74 per barrel and $117 per barrel, respectively. Last year at this time, WTI for April 2012 delivery averaged $102 per barrel and implied volatility averaged 35 percent. The corresponding lower and upper limits of the 95-percent confidence interval were $75 per barrel and $138 per barrel.

U.S. Crude Oil and Liquid Fuels

U.S. Liquid Fuels Consumption. Having fallen 230,000 bbl/d (1.2 percent) in 2011, total liquid fuels consumption declined by an additional 300,000 bbl/d (1.6 percent) in 2012. All of the major petroleum categories contributed to the slide in consumption in 2012 despite the continued economic recovery and little change in year-over-year inflation-adjusted retail fuel prices. Projected total liquid fuels consumption increases by 70,000 bbl/d (0.4 percent) in 2013 and by 60,000 bbl/d in 2014. Most of the consumption growth comes from distillate fuel oil and liquefied petroleum gas, which rise because of continued growth in industrial use as well as the assumption of near-normal weather this winter compared with much warmer-than-normal weather last winter.

Forecast motor gasoline consumption in 2013 and 2014 remains almost unchanged from 2012 because continued slow growth in the driving-age population and highway travel is offset by improvements in the average fuel economy of new vehicles and retirement of older, less-fuel-efficient vehicles.

Distillate fuel consumption averaged 3.8 million bbl/d in 2012, 130,000 bbl/d (3.2 percent) lower than in 2011. Growth in on-highway diesel consumption in 2012 was offset by lower heating oil consumption for space heating (a 5.8-percent drop in heating degree days in the Northeast in 2012) and a decline in rail freight traffic (2.2-percent decline in estimated ton-miles over the first 51 weeks of 2012, as reported by the American Association of Railroads) led by lower coal and grain shipments. EIA expects distillate consumption to increase by 20,000 bbl/d in 2013 and 30,000 bbl/d in 2014 as trucking continues to grow, winter temperatures return to near normal, and coal and grain production begin to recover in the second half of 2013 and increase in 2014.

Consumption of liquefied petroleum gas (and natural gas liquids) increased during 2012 despite the last winter's warm weather because growing supply of natural gas liquids over the last several years contributed to lower prices and increased demand, particularly by the petrochemical industry. Planned expansions at several ethylene plants in 2013 lead to increases in expected liquefied petroleum gas consumption of 40,000 bbl/d in 2013 and 30,000 bbl/d in 2014.

U.S. Liquid Fuels Supply and Imports. EIA expects crude oil production to continue to grow rapidly over the next two years, increasing from an average 6.4 million bbl/d in 2012 to average 7.3 million bbl/d in 2013, an increase of about 0.3 million bbl/d from last month's STEO, and 7.9 million bbl/d in 2014. Central to this projected growth will be ongoing development activity in key onshore basins. Drilling in tight oil plays in the Williston, Western Gulf, and Permian Basins is expected to account for the bulk of forecast production growth over the next two years.

The Williston Basin's Bakken formation in North Dakota and Montana, and the Western Gulf Basin's Eagle Ford formation in Texas currently contribute about two-thirds of U.S. tight oil production. Williston basin production rises from an estimated December 2012 level of 0.84 million bbl/d to 1.19 million bbl/d in December 2014. Western Gulf Basin production rises from an estimated December 2012 level of 1.07 million bbl/d to 1.75 million bbl/d in December 2014. Within the Western Gulf Basin roughly 0.4 million bbl/d of the oil production is outside of the Eagle Ford formation. The Western Gulf Basin accounts for more than half of the onshore domestic liquid production growth over the next two years.

The Permian Basin in West Texas, which includes plays such as Spraberry, Bonespring, and Wolfcamp, is another key growth area. (The term play refers to an oil or natural gas formation with active prospecting and development.) EIA estimates that crude oil production from the Permian Basin reached 1.23 million bbl/d in December 2012. Permian Basin production is projected to increase to 1.4 million bbl/d in December 2014. Although average initial liquids

production volumes from Permian wells have risen, in contrast to other basins, the production forecast for this basin has been scaled back due to lower rig efficiency across all wells being drilled in the region.

Alaska crude oil production reached a seasonal low this year of 400,000 bbl/d in August 2012 when summer maintenance typically decreases volumes, but recovered to 560,000 bbl/d in November. EIA expects Alaskan crude oil production will decline from an average of 530,000 bbl/d in 2012 to 510,000 bbl/d in 2013 and 480,000 bbl/d in 2014.

U.S. Federal Gulf of Mexico (GOM) average daily oil production was 1.17 million bbl/d in September 2012 because of outages early in the month related to Hurricane Isaac. Oil production recovered from the storm by the end of September and is estimated to have increased to 1.34 million bbl/d in November 2012. Average daily production for 2012 is expected to be 1.26 million bbl/d, approximately 60,000 bbl/d lower than during 2011.

EIA expects GOM production to increase to an average 1.37 million bbl/d in 2013. Much of that increase is due to the new projects that started producing in 2012, but do not reach peak production until late 2012 or early 2013, and six new field start-ups with a combined peak production of about 45,000 bbl/d, plus the Na Kika Phase 3 redevelopment project located 144 miles southeast of New Orleans.

Projected GOM production continues to increase in 2014, averaging 1.44 million bbl/d, as several relatively high-volume deepwater projects are expected onstream, including the Jack-St. Malo joint field development, Big Foot, Tubular Bells, and Lucius. Also expected onstream during 2014 is the Atlantis Phase 2 redevelopment project. The timing of and volumetric contribution from these projects is based on currently reported timetables.

Since peaking in 2005 at 12.5 million bbl/d, U.S. liquid fuel net imports, including crude oil, have been falling. Net imports declined to 7.5 million bbl/d in 2012, and EIA expects imports to continue declining to an average of 6.0 million bbl/d by 2014. Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at over 60 percent in 2005 and fell to an average of 40 percent in 2012, and EIA expects the net import share to average 32 percent in 2014 because of continued substantial increases in domestic crude oil production.

U.S. Petroleum Product Prices. Despite similar crude oil prices during 2011 and 2012, U.S. monthly average regular gasoline retail prices increased from an average of $3.53 per gallon in 2011 to average $3.63 per gallon in 2012, driven partly by isolated refinery outages and lower inventory levels on the East and West coasts. U.S. regular gasoline retail prices fell from an average of $3.85 per gallon in September 2012 to an average of $3.31 per gallon in December, which was the lowest average since December 2011. EIA expects regular-grade gasoline retail prices will average $3.44 per gallon and $3.34 per gallon in 2013 and 2014, respectively.

On-highway diesel fuel retail prices averaged $4.12 per gallon in September 2012, and continued tight market conditions and strong demand for exports kept on-highway diesel fuel prices at an average of $3.96 per gallon in December. On November 23, 2012, U.S. week-ending stocks of distillate fuel oil fell to their lowest level since May 30, 2008, despite the higher expected demand during the current winter heating season. Distillate inventories have since recovered, especially in the Northeast, though still remaining well below their five-year average. After averaging $3.97 per gallon in 2012, EIA expects that on-highway diesel fuel retail prices will average $3.87 per gallon in 2013 and $3.78 per gallon in 2014. Wholesale diesel margins (the difference between the wholesale price of diesel and the U.S. average refiner acquisition cost of crude oil) averaged $0.60 per gallon in the first half of 2012, and then climbed to an average of $0.92 per gallon in November, the highest monthly average since October 2005. EIA projects wholesale diesel margins will average $0.75 per gallon in 2013 and $0.63 per gallon in 2014, compared with the previous five-year (2007-11) average of $0.54 per gallon.

Natural Gas

U.S. Natural Gas Consumption. EIA expects that natural gas consumption will average 69.7 billion cubic feet per day (Bcf/d) in 2013 and 69.4 Bcf/d in 2014. While total consumption is relatively unchanged from 2012, the makeup of consumption changes. Because of a warm winter last year, 2012 residential and commercial consumption was very low, and the hot summer (as well as relatively low natural gas prices) led to record-high use of natural gas for power generation. Forecasts for closer-to-normal temperatures in 2013 and 2014 will lead to increases in natural gas used for residential and commercial space heating. These increases are offset by declines in natural gas for power generation, as summer temperatures are expected to be closer to normal, meaning cooler than they were in 2012.

Despite projected declines in electric power consumption from 2012 levels, consumption of natural gas for electric power generation remains high by historical standards and reflects a structural shift toward using more natural gas for power generation. While the shift toward more natural gas for power generation has been most evident in the Southeast, other major consuming areas have also increased natural gas consumption. Increased pipeline flows in New England during the summer months, for example, represent an increasing reliance on natural gas for power generation.

U.S. Natural Gas Production and Imports. This month's STEO expects continued growth in natural gas production, driven largely by onshore production in shale areas. In particular, production in the Marcellus Shale areas of Pennsylvania and West Virginia is expected to continue rising, as recently drilled wells become operational. Despite relatively low natural gas prices, Pennsylvania drilling continues at a strong pace as producers target combination oil-and-gas wells. Production has been rising despite large decreases in the natural gas rig count over the past year. According to Baker Hughes, the natural gas rig count was 431 as of December 28, 2012, compared with 811 at the start of 2012. The oil rig count has also declined in recent months (oil rigs often produce associated natural gas), although declines have been much

smaller than declines in the natural gas rig count. The declines in rig counts, coupled with continued production growth, suggest increases in rig efficiency, which will maintain production levels going forward.

This month's STEO expects that total marketed production will increase from 69.2 Bcf/d in 2012 to 69.8 Bcf/d in 2013, and drop slightly to 69.5 Bcf/d in 2014. EIA expects growth in Lower 48 onshore production will continue through 2014, and will be offset by Gulf of Mexico declines next year.

Domestic supply continues to displace pipeline imports from Canada and liquefied natural gas (LNG) imports. EIA expects pipeline gross imports will stay mostly flat in 2013. Projected pipeline imports drop by 0.4 Bcf/d (4.5 percent) in 2014. Gross exports to Mexico have grown substantially since 2010, but EIA expects exports will stay flat in 2013 and increase by 0.2 Bcf/d (5.5 percent) the following year. LNG imports are expected to remain at minimal levels of less than 0.5 Bcf/d in both 2013 and 2014. Exports mainly arrive at the Elba Island terminal in Georgia and the Everett terminal in New England, either to fulfill long-term contract obligations or to take advantage of temporarily high local prices due to cold snaps and disruptions. Higher prices for LNG elsewhere in the world have made the United States a market of last resort for LNG suppliers.

U.S. Natural Gas Inventories. Inventories of working natural gas in storage remain at high levels, after setting an all-time weekly record in November 2012. As of December 28, working gas stocks totaled 3,517 Bcf, which is 23 Bcf greater than the same time in 2011 and 389 Bcf greater than the previous five-year (2007-11) average, according to EIA's *Weekly Natural Gas Storage Report*. So far this winter, withdrawals have been limited, mainly because of warmer-than-normal temperatures in December. Five-year average weekly withdrawals in December are generally well above 100 billion cubic feet, but that occurred only during the last week of the month. For the week ending December 7, 2012, working gas inventories posted a net *injection* of 2 Bcf. Only two other net injections have been reported in the month of December: one in 2005 and the other time in 1998.

U.S. Natural Gas Prices. Natural gas spot prices averaged $3.34 per MMBtu at the Henry Hub in December 2012, down $0.20 per MMBtu from the November 2012 average and $0.17 per MMBtu more than the December 2011 average. The warm December partially led to the month-over-month decline in prices. Through 2014, EIA expects prices will gradually rise but still remain relatively low. EIA expects the Henry Hub price will average $3.74 per MMBtu in 2013 (compared to $2.75 per MMBtu in 2012) and $3.90 per MMBtu in 2014.

Natural gas futures prices for April 2013 delivery (for the five-day period ending January 3, 2013) averaged $3.38 per MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95-percent confidence interval for April 2013 contracts at $2.42 per MMBtu and $4.73 per MMBtu, respectively. At this time a year ago, the natural gas futures contract for April 2012 averaged $3.11 per MMBtu and the corresponding

lower and upper limits of the 95-percent confidence interval were $2.15 per MMBtu and $4.49 per MMBtu.

Coal

U.S. Coal Consumption. EIA estimates coal consumption in the electric power sector totaled 829 million short tons (MMst) in 2012, the lowest amount since 1992. Lower natural gas prices paid by electric generators led to a significant increase in the share of natural gas-fired generation. Higher natural gas prices, coupled with slightly higher electricity demand, will lead to an increase in coal-fired generation over the forecast period.

U.S. Coal Supply. EIA estimates coal production declined by 6.3 percent in 2012 along with a drop in domestic consumption. Coal production is expected to decline by a further 3.6 percent in 2013 as primary and secondary inventory draws combined with a small increase in coal imports meet a small consumption increase in 2013. Although EIA forecasts that coal consumption will remain flat and that inventories will stabilize in 2014, production is forecast to grow by 3 percent as coal exports rise.

U.S. Coal Trade. EIA estimates coal exports totaled a record 124 MMst in 2012. Continuing economic weakness in Europe and lower international coal prices are expected to contribute to lower coal exports in 2013. U.S. metallurgical coal exports could be reduced if China removes an export tariff on Chinese coke, which steel producers import in lieu of metallurgical coal.

U.S. Coal Prices. Delivered coal prices to the electric power industry increased steadily over the 10-year period ending in 2011, when the delivered coal price averaged $2.39 per MMBtu (a 6-percent increase from 2010). EIA expects that changing market conditions, including weaker domestic demand for coal and higher coal inventories, will slow increases in coal prices and contribute to the shut-in of higher-cost production. EIA forecasts that the delivered coal price will average $2.40 per MMBtu in 2012, $2.44 per MMBtu in 2013, and $2.50 in 2014.

Electricity

U.S. Electricity Consumption. Most regions of the United States experienced temperatures that were much warmer than normal during 2012, in both the winter and the summer. Based on the assumption that temperatures return closer to normal, EIA expects residential electricity sales during the winter months of 2013 will be higher than last year while summer electricity sales will be lower, leading to a projected annual decline of 0.3 percent during 2013. Weather during 2014 is assumed to be similar to that in 2013. The primary driver of residential electricity sales in 2014 is growth in the number of customers, which will be tempered somewhat by increased efficiency in residential electricity consumption. EIA projects retail sales to the residential sector will grow by 0.1 percent during 2014.

Growth in industrial electricity consumption picks up in the second half of 2013 when industrial electricity sales show year-over-year growth of 0.7 percent. During 2014, industrial electricity sales grow by 1.8 percent.

U.S. Electricity Generation. EIA expects total generation of electricity to remain largely unchanged in 2013 and to grow by 94 gigawatthours per day (GWh/d) (0.8 percent) in 2014. An expected 32-percent increase in the price of natural gas delivered to power generators drives a 264-GWh/d reduction in the use of natural gas in 2013, resulting in a fuel share of 27.9 percent of total generation compared with a share of 30.3 percent in 2012. The decline in natural gas generation this year is offset by a 166-GWh/d increase in coal generation (raising the coal share of generation from 37.6 percent in 2012 to 39.0 percent in 2013), a 75-GWh/d increase in generation from renewables, and a 32-GWh/d increase in nuclear generation.

EIA forecasts natural gas will account for 27.5 percent of total generation in 2014 and coal will account for 39.6 percent, both relatively unchanged from the projected 2013 fuel shares. However, there is a high degree of uncertainty in the generation fuel mix forecast. Lower-than-projected natural gas prices along with the industry's response to future environmental regulations could cause the natural gas share of total generation to exceed this forecast.

U.S. Electricity Retail Prices. Rising costs of infrastructure upgrades continue to drive increases in residential electricity rates, although lower fuel prices in recent years have kept growth in retail rates relatively modest. After an increase of 1.3 percent during 2012, EIA expects retail residential electricity prices will grow by 1.9 percent in 2013 and by 2.6 percent in 2014.

Renewables and Carbon Dioxide Emissions

U.S. Renewables. Total renewable energy consumption is estimated to have declined by 2.5 percent in 2012 as the decline in hydropower from 2011 to 2012 more than offset the projected growth in the consumption of other renewable energy forms. This decrease was the result of hydropower production falling by 0.4 quadrillion Btu (13.7 percent) as the Pacific Northwest fell from the unusually high levels seen in 2011. Renewable energy consumption increases 3.6 percent in 2013 as hydropower is projected to grow by 1.7 percent and nonhydropower renewables grow by an average of 4.4 percent. In 2014 the growth in total renewables is projected to continue at a rate of 1.7 percent as a 2.4-percent decline in hydropower is more than offset by a 3.7-percent increase in nonhydropower renewables.

The federal production tax credit (PTC) for wind-powered generation and other renewable energy sources has been extended beyond 2012 as part of the compromise related to the fiscal cliff. This month's STEO does not include the potential effect of the PTC extension on the wind and other renewable energy generation capacity forecasts.

Wind-powered generation grew by 17 percent in 2012. Based on current reporting to EIA, more than 5 gigawatts of wind capacity was scheduled to come on line in December 2012, in addition

to the approximately 6 gigawatts that entered service from January through November of 2012. This is projected to lead to an additional 13-percent increase in wind generation in 2013 as compared to 2012, as this new capacity would be operating for the entire year. Very little new capacity was projected to come on line in 2013 prior to the PTC extension and, as a result, growth in generation in 2014 is projected to be flat. Projections for capacity additions may differ in future STEOs as the impact of the PTC extension is addressed.

Solar energy continues robust growth, although the total amount remains small compared to total U.S. generation. Consumption is projected to grow by 32 percent in 2012, 31 percent in 2013 and 28 percent in 2014.

Because of drought conditions depressing corn harvests throughout the Midwest, fuel ethanol production fell from an average of 900,000 bbl/d during the first half of 2012 to an average of 820,000 bbl/d in the second half of the year. EIA expects ethanol production will remain near current levels through mid-2013 before recovering to pre-drought production levels, averaging 870,000 bbl/d (13.3 billion gallons) for the year. Ethanol production is expected to rebound in 2014 as previously idled capacity comes back on line to meet the increasing Renewable Fuel Standard (RFS) mandate. Ethanol production averages 915,000 bbl/d (14.0 billion gallons) in 2014, meeting the RFS mandate along with banked Renewable Identification Number (RIN) credits generated in previous years. The ethanol share of the gasoline pool increases from an average 9.6 volume percent in 2012 to just under 11 volume percent by the end of 2014, which implies a need to expand from the current 10 gas stations with E-15 blending pumps and 2,500 E-85 stations.

The $1-per-gallon biodiesel excise tax credit was recently retroactively reinstated beginning January 1, 2012, through the end of 2013 as part of the year-end fiscal package. This STEO does not include the possible impact of the biodiesel tax credit on the biodiesel forecast. Biodiesel production averaged about 65,000 bbl/d (1.00 billion gallons) in 2012. Forecast biodiesel production averages 74,000 bbl/d in 2013 and 2014, with biodiesel blending meeting the RFS requirement of 1.28 billion gallons set for 2013.

U.S. Energy-Related Carbon Dioxide Emissions. Fossil fuel emissions are estimated to have declined by 3.4 percent in 2012. This decline is projected to be followed by an increases of 0.9 percent in 2013 and 0.5 percent in 2014.

U.S. Economic Assumptions

This new section of the STEO discusses the macroeconomic assumptions built into EIA's short-term energy forecasts. The economic projections in the STEO are derived from the IHS/Global Insight (GI) macroeconomic model with EIA's energy price forecasts as model inputs. The GI model used in this STEO assumes that there are tax increases on higher-income earners beginning in 2013 and modest cuts to government spending, which are implemented in 2014.

Current Trends. Recent indicators continue to point to a modest economic recovery, and key sectors such as housing are improving. The NAHB Housing Index has risen for 8 consecutive months to levels last seen in 2006. The unemployment rate in December was 7.8 percent, unchanged from November, while nonfarm payroll employment grew by 155,000. The ISM Manufacturing Index rose in December to 50.7 (a value above 50 indicates expansion). One important indicator of financial market uncertainty, the Federal Reserve Bank of Chicago's National Financial Conditions Index (NFCI), is currently below its average level of zero and relatively unchanged from November.

U.S. Output. The STEO forecast for U.S. gross domestic product (GDP) growth in 2013 is 1.8 percent, rising to 2.6 percent in 2014. Growth starts out slowly in 2013 and then gradually increases throughout the year, reaching 2.2 percent in the fourth quarter of 2013. The same pattern is repeated in 2014, with real GDP growth reaching 2.9 percent in the fourth quarter. Residential investment and exports are important drivers of this growth in both years.

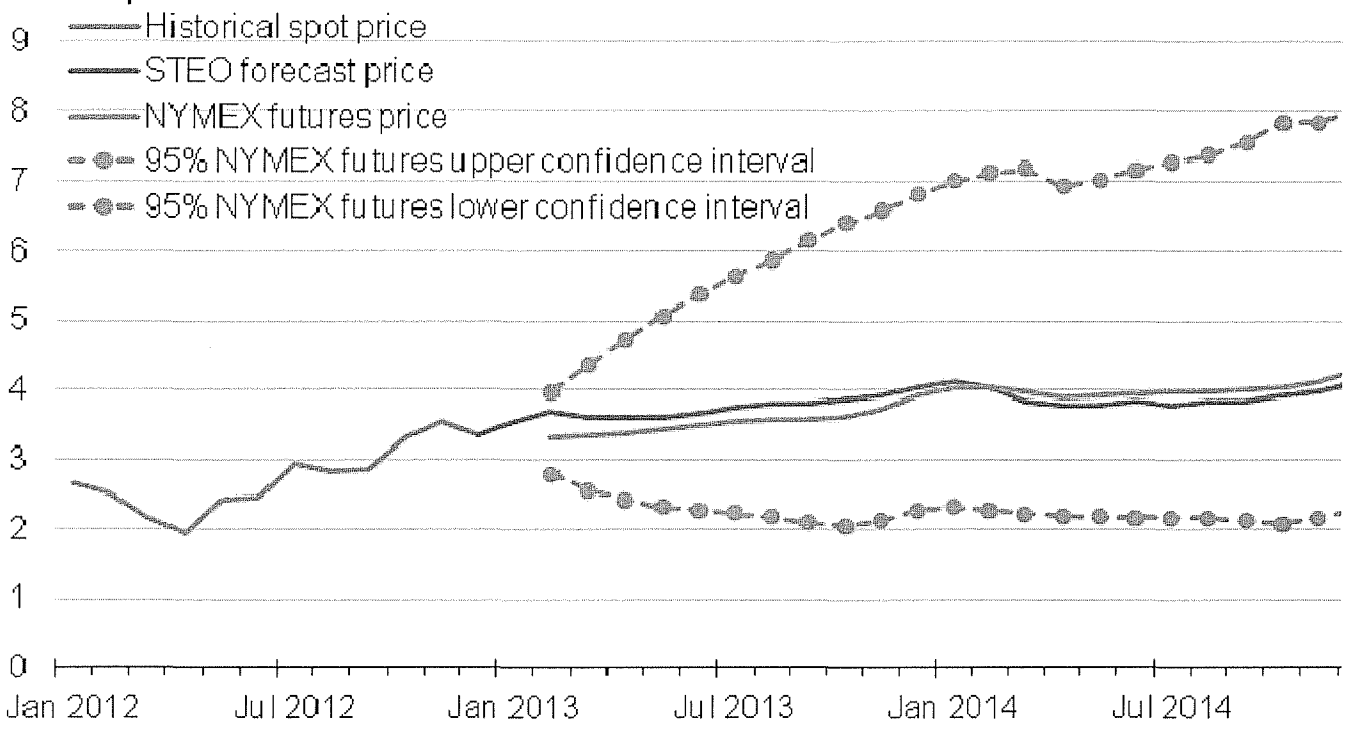
Total industrial production grows at a faster rate than real GDP in 2013 and 2014, at 1.9 percent and 2.9 percent, respectively. Industrial production growth in the manufacturing sector is slower than total production in 2013 at 1.8 percent, but accelerates to 3.4 percent in 2014. Both of these indexes mirror the rises in demand due to higher growth in real GDP.

U.S. Income and Expenditures. Consumption expenditures begin to pick up in 2014, rising by 2.4 percent compared with 2.0-percent growth forecast in 2013. This is partly due to higher real disposable income, which rises during this time period as well. Private fixed investment jumps to 9.2-percent growth in 2014 from 5.8 percent the year before, highlighting its importance for overall economic expansion, and export growth accelerates as well. Government expenditures fall more than 1 percent in both years.

U.S. Employment, Housing, and Prices. The unemployment rate in the forecast gradually falls from an average of 7.8 percent in 2013 to 7.5 percent in 2014. This will be accompanied by non-farm employment growth averaging just above 1.5 percent in both years. Housing starts stand out in this forecast, as they are projected to increase nearly 25 percent in 2013 and over 32 percent in 2014. Both consumer and producer prices continue to increase at a moderate pace. The consumer price index (CPI) for urban consumers averages annual growth of 1.8 percent in 2013 and 1.9 percent in 2014. The producer price index (PPI) for all commodities is forecast to increase by 1.4 percent year-on-year in 2013, slowing to 0.8-percent growth in 2014.

Henry Hub Natural Gas Price

dollars per million btu



Note: Confidence interval derived from options market information for the 5 trading days ending January 3, 2013. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Source: Short-Term Energy Outlook, January 2013

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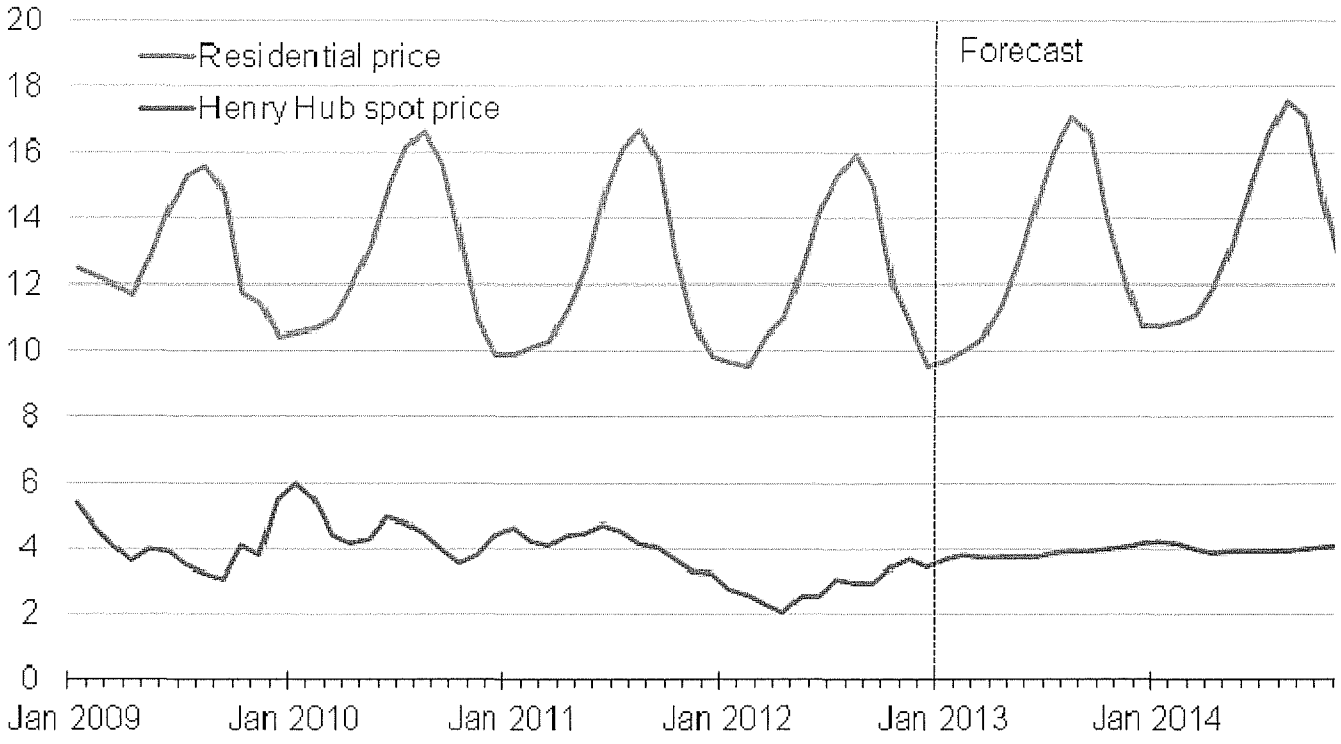
U.S. Natural Gas Prices

dollars per thousand cubic feet



Source: Short-Term Energy Outlook, January 2013

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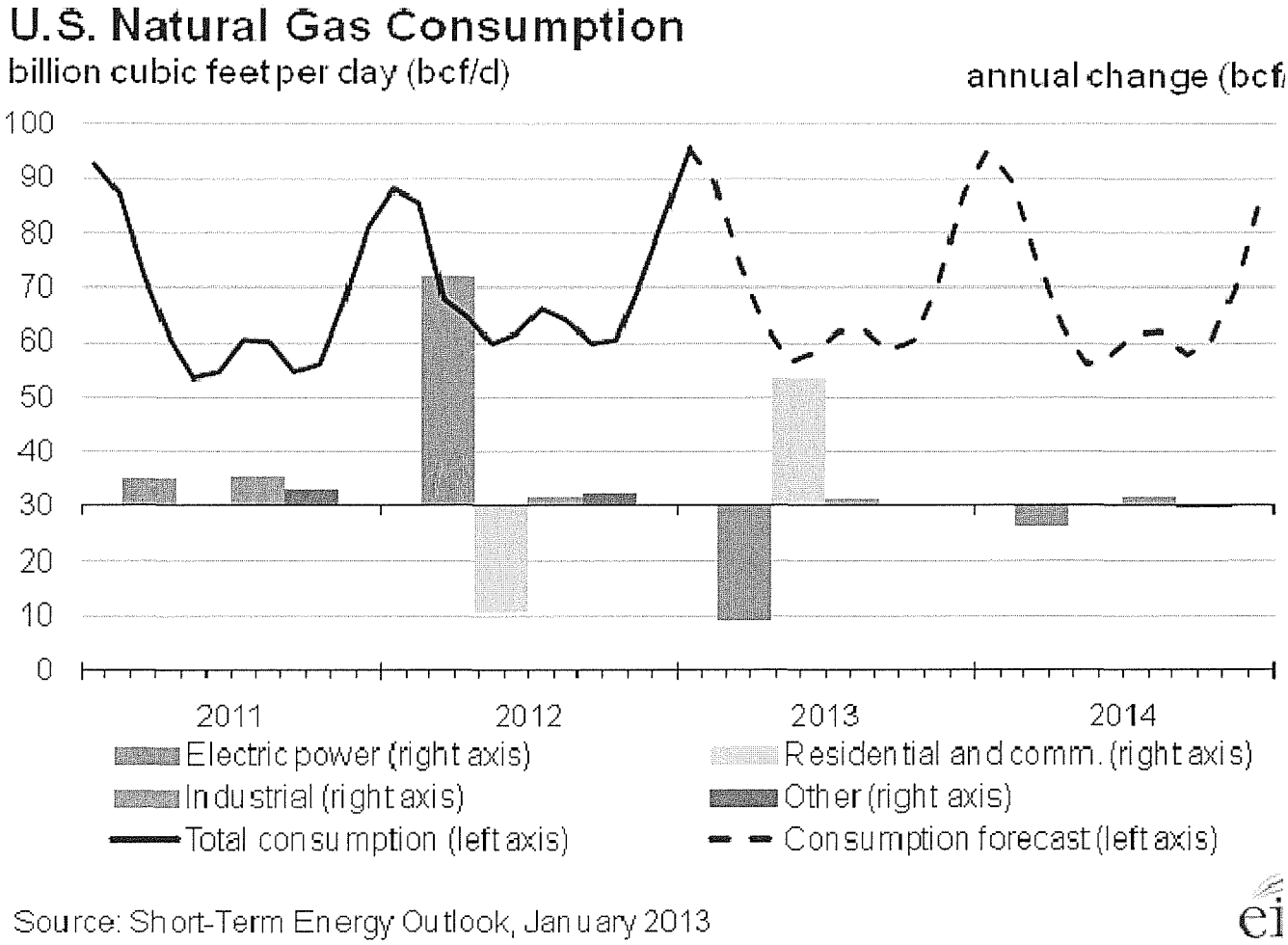
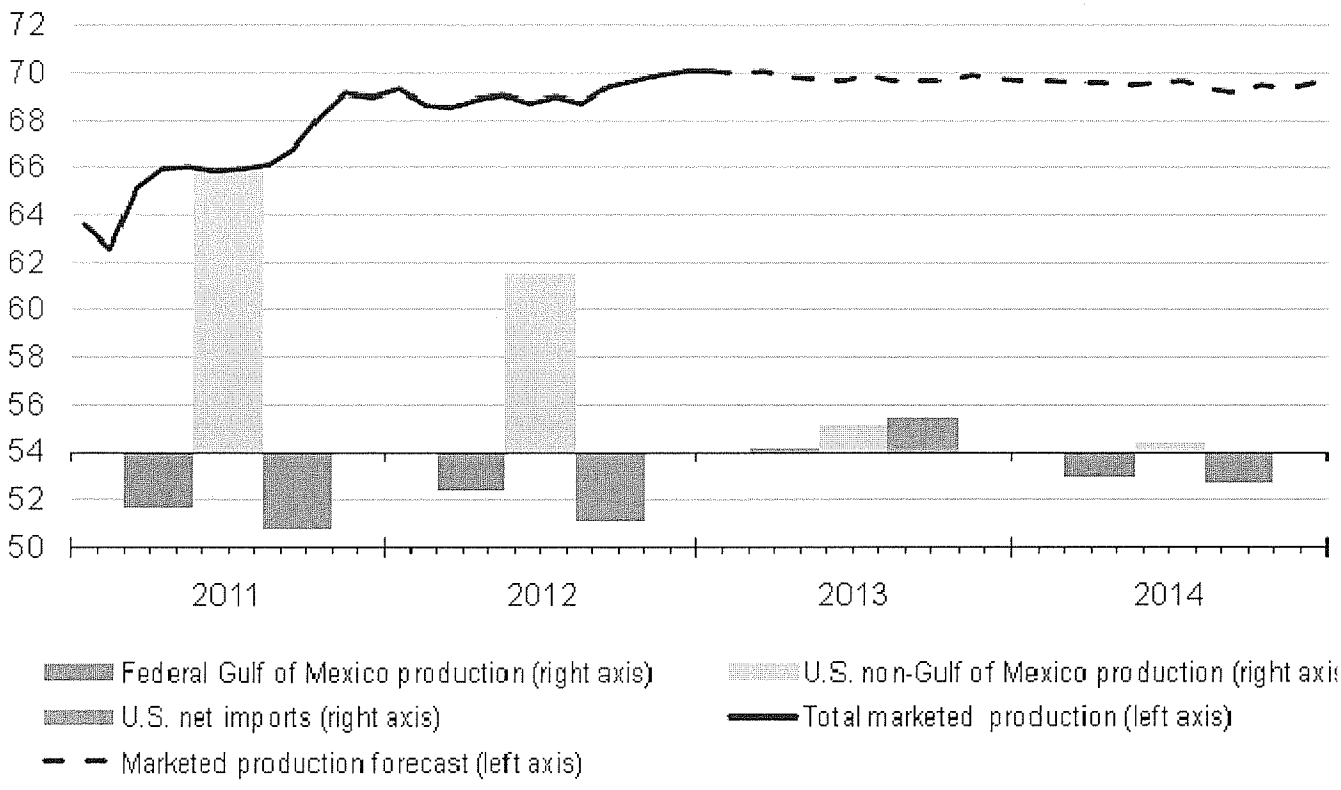


Source: Short-Term Energy Outlook, January 2013

U.S. Natural Gas Production and Imports

billion cubic feet per day (bcf/d) annual change (bcf



Source: Short-Term Energy Outlook, January 2013

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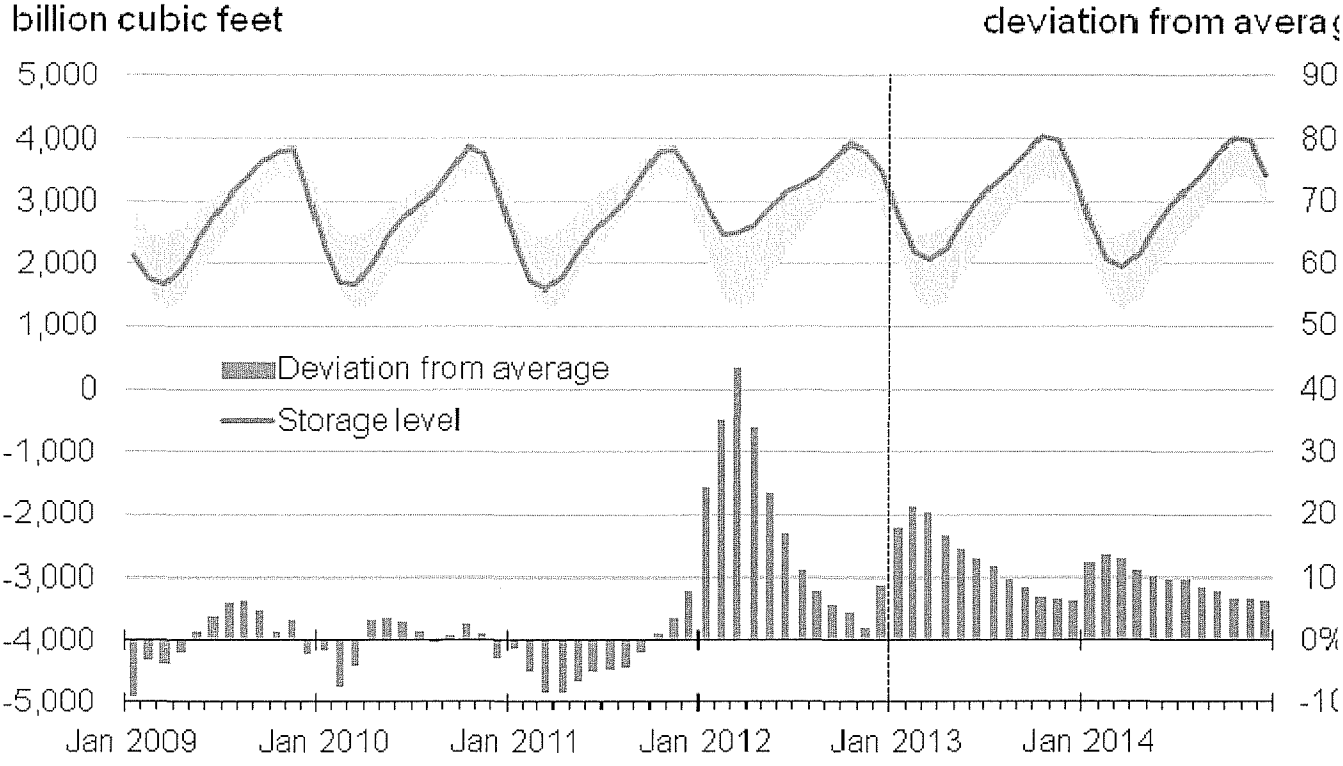
U.S. Working Natural Gas in Storage



Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2008 - Dec. 2012.

Source: Short-Term Energy Outlook, January 2013

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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, 2012										**$311,764**
May	$30,099	$0	$2,016	$32,115	13,138	$0.5102	$6,702		$25,413	337,177
June	52,819	0	2,192	55,011	6,558	1.0137	4,625	2/	50,386	387,563
July	57,568	0	2,542	60,110	5,776	1.0137	5,855		54,255	441,818
August	58,888	0	2,918	61,806	5,143	1.0137	5,213		56,593	498,411
September	26,138	0	3,308	29,446	6,241	1.0137	6,327		23,119	521,530
October	36,902	0	3,454	40,356	10,185	1.0137	10,325		30,031	551,561
November	8,143	0	3,651	11,794	20,404	1.0137	20,684		(8,890)	542,671
December	7	0	3,572	3,579	31,222	1.0137	31,650		(28,071)	514,600
Balance @ December 31, 2012										**$514,600**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 4,017.3 dk @ $0.5102 and 2,540.6 dk @ $1.0137.

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, 2012									**($72,396)**
May	($11,426)	$0	($557)	($11,983)	23,670	($0.0178)	($422)	($11,561)	(83,957)
June	(6,055)	0	(637)	(6,692)	13,697	(0.2915)	(1,509) 2/	(5,183)	(89,140)
July	(16,584)	0	(671)	(17,255)	13,108	(0.2915)	(3,821)	(13,434)	(102,574)
August	(2,356)	0	(765)	(3,121)	14,195	(0.2915)	(4,138)	1,017	(101,557)
September	(20,241)	0	(754)	(20,995)	21,085	(0.2915)	(6,146)	(14,849)	(116,406)
October	325	0	(859)	(534)	37,029	(0.2915)	(10,794)	10,260	(106,146)
November	6,923	0	(784)	6,139	41,796	(0.2915)	(12,184)	18,323	(87,823)
December	(3,340)	0	(652)	(3,992)	49,581	(0.2915)	(14,452)	10,460	(77,363)
Balance @ December 31, 2012									**($77,363)**

1/ Interest calculated at 13.3%, the authorized rate of return.
2/ Reflects 9,073.4 dk @ ($0.0178) and 4,623.6 dk @ ($0.2915).