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PUCO EXHIBIT FILING

Date of Hearing: 10/29/2015

Case No. 14-1297-EL-SSO

PUCO Case Caption: In the Matter of the Application of Ohio Edison, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

List of exhibits being filed: Volume XXXV

Company 153

Sierra Club 85, 86, 87, 88

IGS 14, 15, 16, 17, 19

OCC 6

Reporter's Signature: Karen Sue Gibson

Date Submitted: 10/30/2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan. : Case No. 14-1297-EL-SSO

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PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 9:00 a.m. on Thursday, October 29, 2015.

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VOLUME XXXV

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ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
(614) 224-9481 - (800) 223-9481
Fax - (614) 224-5724

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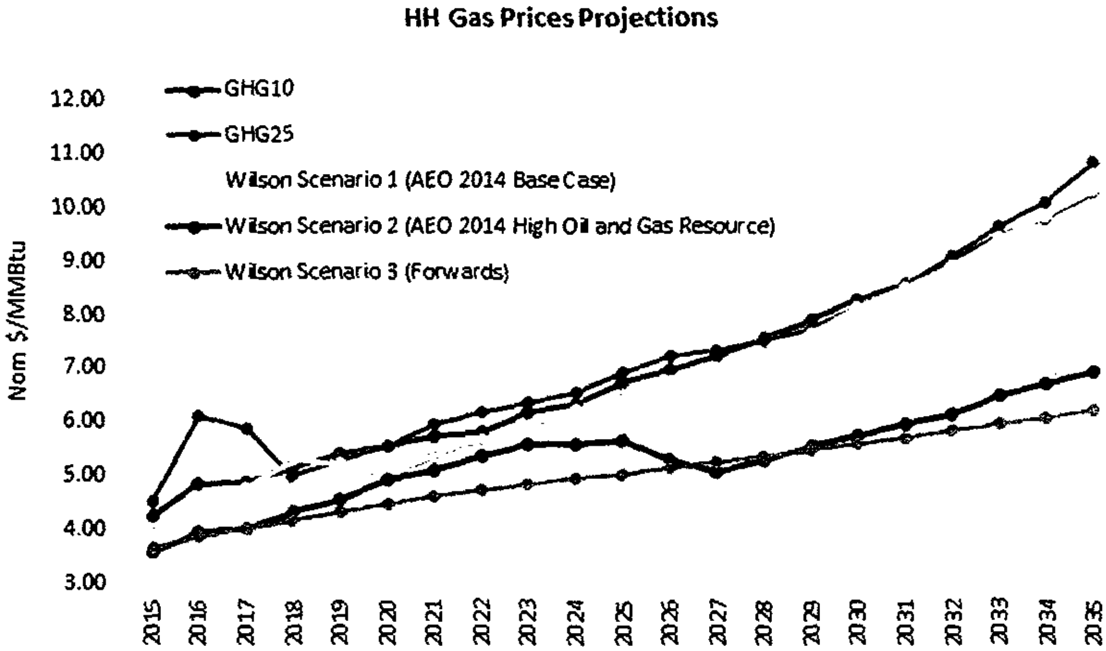
Figure 9 (Corrected)
EIA Gas Prices-GHG Cases and Wilson Scenarios



U.S. Energy Information Administration

NATURAL GAS

OVERVIEW | DATA | ANALYSIS & PROJECTIONS | GLOSSARY › | FAQS ›

Referring Pages:

- Natural Gas Futures Prices (NYMEX)

View History: ◉ Daily ○ Weekly ○ Monthly ○ Annual   Download Data (XLS File)

Henry Hub Natural Gas Spot Price

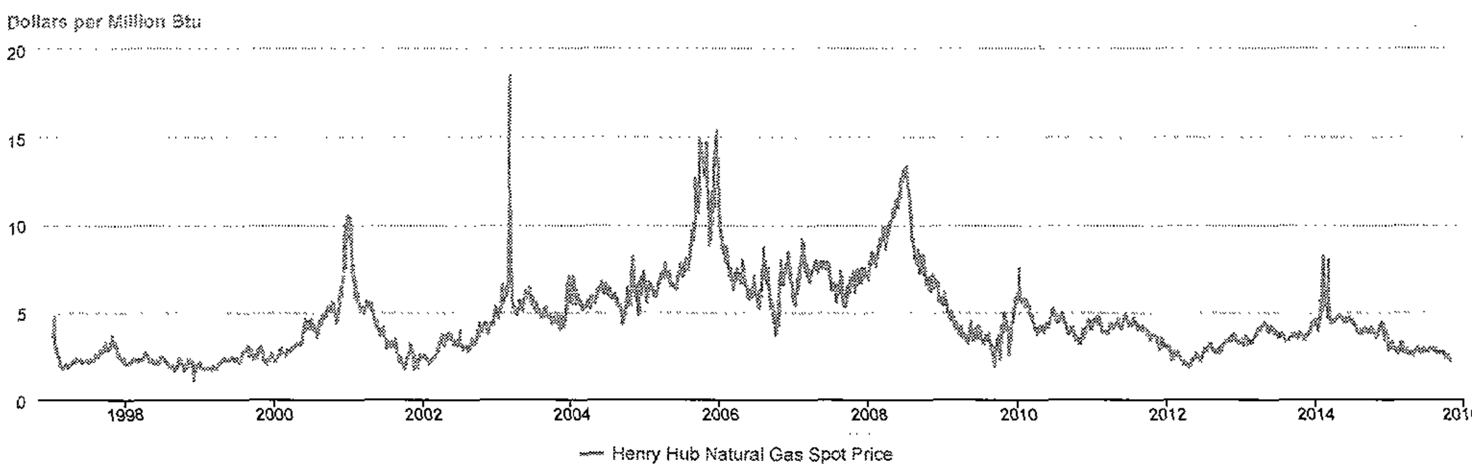


Chart Tools

no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

Henry Hub Natural Gas Spot Price (Dollars per Million Btu)

Week Of	Mon	Tue	Wed	Thu	Fri
1997 Jan- 6 to Jan-10		3.82	3.80	3.61	3.92
1997 Jan-13 to Jan-17	4.00	4.01	4.34	4.71	3.91
1997 Jan-20 to Jan-24	3.26	2.99	3.05	2.96	2.62
1997 Jan-27 to Jan-31	2.98	3.05	2.91	2.86	2.77
1997 Feb- 3 to Feb- 7	2.49	2.59	2.65	2.51	2.39
1997 Feb-10 to Feb-14	2.42	2.34	2.42	2.22	2.12
1997 Feb-17 to Feb-21		1.84	1.95	1.92	1.92
1997 Feb-24 to Feb-28	1.92	1.77	1.81	1.80	1.78
1997 Mar- 3 to Mar- 7	1.80	1.87	1.92	1.82	1.89
1997 Mar-10 to Mar-14	1.95	1.92	1.96	1.98	1.97
1997 Mar-17 to Mar-21	2.01	1.91	1.88	1.88	1.87
1997 Mar-24 to Mar-28	1.80	1.85	1.85	1.84	
1997 Mar-31 to Apr- 4	1.84	1.95	1.85	1.87	1.91
1997 Apr- 7 to Apr-11	1.99	2.01	1.96	1.97	1.98
1997 Apr-14 to Apr-18	2.00	2.00	2.02	2.08	2.10
1997 Apr-21 to Apr-25	2.09	2.10	2.22	2.11	2.16
1997 Apr-28 to May- 2	2.10	2.09	2.16	2.19	2.21
1997 May- 5 to May- 9	2.23	2.25	2.34	2.33	2.30
1997 May-12 to May-16	2.27	2.18	2.22	2.25	2.19
1997 May-19 to May-23	2.25	2.22	2.21	2.22	2.20
1997 May-26 to May-30		2.29	2.34	2.29	2.23
1997 Jun- 2 to Jun- 6	2.20	2.11	2.19	2.18	2.19

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1997 Jun- 9 to Jun-13	2.19	2.16	2.16	2.14	2.15
1997 Jun-16 to Jun-20	2.20	2.20	2.22	2.23	2.25
1997 Jun-23 to Jun-27	2.29	2.32	2.32	2.23	2.17
1997 Jun-30 to Jul- 4	2.17	2.16	2.14	2.11	
1997 Jul- 7 to Jul-11	2.13	2.13	2.16	2.15	2.16
1997 Jul-14 to Jul-18	2.18	2.21	2.24	2.29	2.26
1997 Jul-21 to Jul-25	2.17	2.18	2.20	2.24	2.22
1997 Jul-28 to Aug- 1	2.19	2.23	2.19	2.23	2.24
1997 Aug- 4 to Aug- 8	2.26	2.33	2.38	2.50	2.38
1997 Aug-11 to Aug-15	2.53	2.56	2.45	2.57	2.53
1997 Aug-18 to Aug-22	2.56	2.61	2.62	2.45	2.47
1997 Aug-25 to Aug-29	2.53	2.58	2.51	2.57	2.69
1997 Sep- 1 to Sep- 5		2.82	2.86	2.73	2.67
1997 Sep- 8 to Sep-12	2.67	2.74	2.74	2.78	2.86
1997 Sep-15 to Sep-19	2.88	2.83	2.75	2.84	2.94
1997 Sep-22 to Sep-26	2.98	3.09	3.03	3.05	3.24
1997 Sep-29 to Oct- 3	3.09	2.96	3.08	2.97	2.91
1997 Oct- 6 to Oct-10	2.96	2.81	2.80	2.80	2.78
1997 Oct-13 to Oct-17	2.87	2.84	2.84	2.94	2.97
1997 Oct-20 to Oct-24	3.05	3.13	3.24	3.34	3.29
1997 Oct-27 to Oct-31	3.46	3.61	3.45	3.34	3.22
1997 Nov- 3 to Nov- 7	3.23	3.15	3.18	3.20	3.05
1997 Nov-10 to Nov-14	3.20	3.26	3.28	3.27	3.25
1997 Nov-17 to Nov-21	3.10	3.00	2.97	2.77	2.59
1997 Nov-24 to Nov-28	2.63	2.51	2.50		
1997 Dec- 1 to Dec- 5	2.52	2.61	2.53	2.48	2.42
1997 Dec- 8 to Dec-12	2.30	2.35	2.45	2.30	2.30
1997 Dec-15 to Dec-19	2.25	2.29	2.38	2.37	2.39
1997 Dec-22 to Dec-26	2.36	2.24	2.06		2.18
1997 Dec-29 to Jan- 2	2.33	2.27	2.27		2.16
1998 Jan- 5 to Jan- 9	2.05	2.16	2.13	2.11	2.09
1998 Jan-12 to Jan-16	2.01	2.03	2.05	2.07	2.11
1998 Jan-19 to Jan-23		2.12	2.09	2.10	2.14
1998 Jan-26 to Jan-30	2.09	2.06	2.09	2.07	2.09
1998 Feb- 2 to Feb- 6	2.23	2.27	2.23	2.31	2.35
1998 Feb- 9 to Feb-13	2.25	2.18	2.21	2.20	2.22
1998 Feb-16 to Feb-20		2.18	2.19	2.22	2.20
1998 Feb-23 to Feb-27	2.20	2.19	2.21	2.28	2.23
1998 Mar- 2 to Mar- 6	2.26	2.24	2.19	2.12	2.10
1998 Mar- 9 to Mar-13	2.17	2.25	2.25	2.23	2.21
1998 Mar-16 to Mar-20	2.20	2.20	2.21	2.25	2.28
1998 Mar-23 to Mar-27	2.33	2.29	2.33	2.29	2.26
1998 Mar-30 to Apr- 3	2.32	2.34	2.45	2.43	2.51
1998 Apr- 6 to Apr-10	2.51	2.51	2.65	2.61	
1998 Apr-13 to Apr-17	2.52	2.42	2.48	2.48	2.40
1998 Apr-20 to Apr-24	2.40	2.46	2.46	2.35	2.31
1998 Apr-27 to May- 1	2.29	2.27	2.29	2.18	2.11
1998 May- 4 to May- 8	2.10	2.19	2.12	2.16	2.11
1998 May-11 to May-15	2.19	2.23	2.24	2.18	2.18
1998 May-18 to May-22	2.19	2.17	2.18	2.11	2.02
1998 May-25 to May-29		2.10	2.10	2.04	2.10
1998 Jun- 1 to Jun- 5	2.10	2.20	2.13	2.04	2.01
1998 Jun- 8 to Jun-12	2.00	2.01	1.98	1.99	2.01
1998 Jun-15 to Jun-19	2.08	2.10	2.05	2.14	2.20
1998 Jun-22 to Jun-26	2.35	2.35	2.40	2.39	2.40
1998 Jun-29 to Jul- 3	2.36	2.39	2.46	2.36	
1998 Jul- 6 to Jul-10	2.38	2.35	2.39	2.38	2.32
1998 Jul-13 to Jul-17	2.30	2.23	2.21	2.15	2.15
1998 Jul-20 to Jul-24	2.18	2.09	2.00	2.00	1.97
1998 Jul-27 to Jul-31	2.00	1.97	1.99	1.95	1.85
1998 Aug- 3 to Aug- 7	1.84	1.90	1.91	1.85	1.82
1998 Aug-10 to Aug-14	1.87	1.87	1.85	1.83	1.83
1998 Aug-17 to Aug-21	1.93	1.94	1.96	1.90	1.93
1998 Aug-24 to Aug-28	1.90	1.89	1.83	1.76	1.66
1998 Aug-31 to Sep- 4	1.61	1.84	1.72	1.71	1.71

1998 Sep- 7 to Sep-11		1.81	1.78	1.88	1.86
1998 Sep-14 to Sep-18	1.86	1.94	2.15	2.12	2.27
1998 Sep-21 to Sep-25	2.18	2.29	2.19	2.17	2.38
1998 Sep-28 to Oct- 2	2.23	2.06	2.22	2.33	2.14
1998 Oct- 5 to Oct- 9	2.09	2.01	2.05	2.02	1.80
1998 Oct-12 to Oct-16	1.75	1.70	1.80	1.75	1.64
1998 Oct-19 to Oct-23	1.74	1.95	2.04	1.95	1.84
1998 Oct-26 to Oct-30	1.92	1.85	1.70	2.00	2.00
1998 Nov- 2 to Nov- 6	1.84	2.10	2.11	2.26	2.25
1998 Nov- 9 to Nov-13	2.28	2.30	2.33	2.21	2.21
1998 Nov-16 to Nov-20	2.19	2.12	2.10	2.10	2.07
1998 Nov-23 to Nov-27	2.02	2.08	2.13		
1998 Nov-30 to Dec- 4	1.63	1.41	1.40	1.21	1.05
1998 Dec- 7 to Dec-11	1.44	1.79	1.64	1.59	1.55
1998 Dec-14 to Dec-18	1.80	1.86	1.95	2.02	2.02
1998 Dec-21 to Dec-25	2.05	1.96	1.88	1.89	
1998 Dec-28 to Jan- 1	1.79	1.82	1.81	1.95	
1999 Jan- 4 to Jan- 8	2.10	2.05	2.04	1.91	1.90
1999 Jan-11 to Jan-15	1.83	1.82	1.87	1.77	1.78
1999 Jan-18 to Jan-22		1.77	1.81	1.85	1.82
1999 Jan-25 to Jan-29	1.76	1.73	1.75	1.75	1.83
1999 Feb- 1 to Feb- 5	1.75	1.78	1.80	1.79	1.81
1999 Feb- 8 to Feb-12	1.81	1.82	1.80	1.78	1.82
1999 Feb-15 to Feb-19		1.79	1.79	1.80	1.79
1999 Feb-22 to Feb-26	1.77	1.75	1.73	1.64	1.63
1999 Mar- 1 to Mar- 5	1.65	1.67	1.68	1.72	1.74
1999 Mar- 8 to Mar-12	1.87	1.86	1.94	1.87	1.81
1999 Mar-15 to Mar-19	1.75	1.75	1.75	1.75	1.73
1999 Mar-22 to Mar-26	1.74	1.80	1.79	1.80	1.83
1999 Mar-29 to Apr- 2	1.80	1.89	2.02	1.95	
1999 Apr- 5 to Apr- 9	2.03	1.98	2.03	2.07	2.10
1999 Apr-12 to Apr-16	2.06	2.14	2.11	2.14	2.14
1999 Apr-19 to Apr-23	2.10	2.18	2.17	2.24	2.23
1999 Apr-26 to Apr-30	2.23	2.32	2.31	2.37	2.25
1999 May- 3 to May- 7	2.23	2.32	2.36	2.32	2.25
1999 May-10 to May-14	2.25	2.29	2.19	2.21	2.28
1999 May-17 to May-21	2.31	2.30	2.27	2.26	2.21
1999 May-24 to May-28	2.19	2.18	2.22	2.27	2.29
1999 May-31 to Jun- 4		2.34	2.36	2.35	2.31
1999 Jun- 7 to Jun-11	2.41	2.38	2.39	2.37	2.30
1999 Jun-14 to Jun-18	2.29	2.28	2.28	2.24	2.24
1999 Jun-21 to Jun-25	2.22	2.23	2.25	2.26	2.27
1999 Jun-28 to Jul- 2	2.25	2.33	2.34	2.29	2.26
1999 Jul- 5 to Jul- 9		2.29	2.20	2.19	2.17
1999 Jul-12 to Jul-16	2.12	2.14	2.16	2.12	2.18
1999 Jul-19 to Jul-23	2.20	2.24	2.25	2.32	2.42
1999 Jul-26 to Jul-30	2.55	2.55	2.58	2.67	2.55
1999 Aug- 2 to Aug- 6	2.51	2.61	2.64	2.69	2.69
1999 Aug- 9 to Aug-13	2.73	2.77	2.79	2.73	2.71
1999 Aug-16 to Aug-20	2.73	2.70	2.75	2.87	2.97
1999 Aug-23 to Aug-27	2.95	3.01	3.10	2.97	2.87
1999 Aug-30 to Sep- 3	2.85	2.84	2.71	2.56	2.47
1999 Sep- 6 to Sep-10		2.56	2.66	2.75	2.84
1999 Sep-13 to Sep-17	2.80	2.66	2.52	2.47	2.45
1999 Sep-20 to Sep-24	2.49	2.33	2.30	2.45	2.54
1999 Sep-27 to Oct- 1	2.51	2.52	2.57	2.31	2.39
1999 Oct- 4 to Oct- 8	2.49	2.45	2.48	2.49	2.35
1999 Oct-11 to Oct-15	2.53	2.65	2.81	2.70	2.66
1999 Oct-18 to Oct-22	2.82	2.89	2.90	2.99	3.00
1999 Oct-25 to Oct-29	2.98	2.96	3.02	2.97	2.76
1999 Nov- 1 to Nov- 5	2.73	2.81	2.82	2.75	2.62
1999 Nov- 8 to Nov-12	2.59	2.44	2.39	2.38	2.16
1999 Nov-15 to Nov-19	2.33	2.23	2.24	2.22	2.16
1999 Nov-22 to Nov-26	2.05	1.99	1.96		

1999 Nov-29 to Dec- 3	2.25	2.22	2.17	2.18	2.16
1999 Dec- 6 to Dec-10	2.19	2.16	2.23	2.20	2.27
1999 Dec-13 to Dec-17	2.35	2.49	2.54	2.52	2.55
1999 Dec-20 to Dec-24	2.67	2.59	2.45	2.42	
1999 Dec-27 to Dec-31	2.36	2.32	2.34	2.30	
2000 Jan- 3 to Jan- 7		2.16	2.17	2.18	2.19
2000 Jan-10 to Jan-14	2.20	2.23	2.25	2.29	2.28
2000 Jan-17 to Jan-21		2.35	2.40	2.53	2.55
2000 Jan-24 to Jan-28	2.55	2.66	2.73	2.76	2.84
2000 Jan-31 to Feb- 4	2.69	2.81	2.91	2.85	2.78
2000 Feb- 7 to Feb-11	2.81	2.60	2.62	2.65	2.65
2000 Feb-14 to Feb-18	2.61	2.61	2.65	2.66	2.65
2000 Feb-21 to Feb-25		2.55	2.50	2.52	2.51
2000 Feb-28 to Mar- 3	2.60	2.65	2.71	2.80	2.72
2000 Mar- 6 to Mar-10	2.76	2.78	2.74	2.69	
2000 Mar-13 to Mar-17	2.79	2.83	2.76	2.84	2.81
2000 Mar-20 to Mar-24	2.73	2.74	2.78	2.76	2.82
2000 Mar-27 to Mar-31	2.82	2.94	2.92	2.83	2.88
2000 Apr- 3 to Apr- 7	2.92	2.87	2.86	2.98	2.99
2000 Apr-10 to Apr-14	2.97	2.98	3.05	3.05	3.11
2000 Apr-17 to Apr-21	3.13	3.12	3.12	3.07	
2000 Apr-24 to Apr-28	3.12	3.18	3.12	3.06	3.09
2000 May- 1 to May- 5	3.16	3.20	3.18	3.09	3.11
2000 May- 8 to May-12	3.12	3.25	3.20	3.37	3.35
2000 May-15 to May-19	3.37	3.45	3.49	3.73	3.76
2000 May-22 to May-26	3.95	3.85	3.94	4.18	4.29
2000 May-29 to Jun- 2		4.35	4.52	4.39	4.21
2000 Jun- 5 to Jun- 9	4.17	4.48	4.23	3.96	4.14
2000 Jun-12 to Jun-16	4.22	4.27	4.16	4.38	4.45
2000 Jun-19 to Jun-23	4.38	4.02	4.14	4.44	4.42
2000 Jun-26 to Jun-30	4.37	4.55	4.44	4.25	4.36
2000 Jul- 3 to Jul- 7	4.36		4.24	4.02	4.00
2000 Jul-10 to Jul-14	4.19	4.17	4.29	4.08	4.17
2000 Jul-17 to Jul-21	4.13	3.99	4.07	3.86	3.88
2000 Jul-24 to Jul-28	3.74	3.63	3.59	3.75	3.89
2000 Jul-31 to Aug- 4	3.75	3.78	4.05	4.23	4.25
2000 Aug- 7 to Aug-11	4.39	4.46	4.48	4.43	4.44
2000 Aug-14 to Aug-18	4.42	4.24	4.24	4.35	4.38
2000 Aug-21 to Aug-25	4.60	4.80	4.67	4.53	4.55
2000 Aug-28 to Sep- 1	4.62	4.60	4.61	4.76	4.70
2000 Sep- 4 to Sep- 8		4.81	4.89	4.85	4.74
2000 Sep-11 to Sep-15	4.85	4.96	5.06	5.10	5.28
2000 Sep-18 to Sep-22	5.06	5.22	5.24	5.16	5.16
2000 Sep-25 to Sep-29	5.12	5.28	5.34	5.20	5.10
2000 Oct- 2 to Oct- 6	5.24	5.29	5.22	5.21	5.04
2000 Oct- 9 to Oct-13	5.09	5.16	5.10	5.54	5.43
2000 Oct-16 to Oct-20	5.34	5.27	5.36	5.04	4.84
2000 Oct-23 to Oct-27	4.82	4.84	4.64	4.61	4.48
2000 Oct-30 to Nov- 3	4.56	4.37	4.40	4.50	4.64
2000 Nov- 6 to Nov-10	4.60	4.68	4.92	5.34	5.24
2000 Nov-13 to Nov-17	5.59	5.81	5.95	5.94	5.62
2000 Nov-20 to Nov-24	6.23	6.35	6.30		
2000 Nov-27 to Dec- 1	6.24	5.90	5.93	6.31	6.53
2000 Dec- 4 to Dec- 8	7.41	8.03	8.75	8.48	8.13
2000 Dec-11 to Dec-15	9.96	8.58	7.80	7.48	8.03
2000 Dec-18 to Dec-22	9.28	9.11	9.95	10.49	10.48
2000 Dec-25 to Dec-29		10.23	9.58	9.22	10.48
2001 Jan- 1 to Jan- 5		9.97	9.71	9.45	10.03
2001 Jan- 8 to Jan-12	10.31	9.95	9.91	8.95	8.75
2001 Jan-15 to Jan-19		8.16	7.85	7.09	7.61
2001 Jan-22 to Jan-26	7.70	7.02	6.81	6.81	7.00
2001 Jan-29 to Feb- 2	6.76	5.96	5.83	5.82	6.76
2001 Feb- 5 to Feb- 9	6.15	5.59	5.67	6.24	6.24
2001 Feb-12 to Feb-16	5.74	5.58	5.89	5.35	5.57
2001 Feb-19 to Feb-23		5.17	5.20	5.11	5.05

2001 Feb-26 to Mar- 2	5.07	5.07	5.25	5.25	5.06
2001 Mar- 5 to Mar- 9	5.32	5.27	5.22	5.25	5.13
2001 Mar-12 to Mar-16	4.98	5.08	4.99	5.27	5.27
2001 Mar-19 to Mar-23	5.27	5.27	5.16	5.16	5.16
2001 Mar-26 to Mar-30	5.23	5.47	5.60	5.31	5.35
2001 Apr- 2 to Apr- 6	5.25	5.25	5.24	5.27	5.33
2001 Apr- 9 to Apr-13	5.45	5.55	5.45	5.32	
2001 Apr-16 to Apr-20	5.48	5.36	5.15	5.06	5.00
2001 Apr-23 to Apr-27	5.09	5.13	4.98	4.92	4.83
2001 Apr-30 to May- 4	4.73	4.55	4.54	4.46	4.50
2001 May- 7 to May-11	4.33	4.22	4.15	4.17	4.25
2001 May-14 to May-18	4.28	4.46	4.46	4.20	4.15
2001 May-21 to May-25	4.14	4.04	4.11	4.12	3.83
2001 May-28 to Jun- 1		3.86	3.66	3.73	3.70
2001 Jun- 4 to Jun- 8	3.98	3.93	3.76	3.68	3.62
2001 Jun-11 to Jun-15	3.91	4.05	4.13	3.92	3.86
2001 Jun-18 to Jun-22	3.91	3.96	3.83	3.69	3.68
2001 Jun-25 to Jun-29	3.56	3.46	3.39	3.20	2.91
2001 Jul- 2 to Jul- 6	2.92	3.00		3.09	2.99
2001 Jul- 9 to Jul-13	3.10	3.20	3.21	3.29	3.15
2001 Jul-16 to Jul-20	3.08	3.14	3.15	3.01	2.97
2001 Jul-23 to Jul-27	3.02	3.00	3.06	3.26	3.06
2001 Jul-30 to Aug- 3	3.28	3.31	3.27	3.15	3.06
2001 Aug- 6 to Aug-10	3.07	3.16	3.11	3.10	2.99
2001 Aug-13 to Aug-17	3.00	3.05	3.15	3.46	3.24
2001 Aug-20 to Aug-24	3.17	3.18	3.20	2.87	2.77
2001 Aug-27 to Aug-31	2.61	2.57	2.46	2.47	2.15
2001 Sep- 3 to Sep- 7		2.23	2.34	2.43	2.36
2001 Sep-10 to Sep-14	2.38	2.38	2.44	2.39	2.41
2001 Sep-17 to Sep-21	2.36	2.18	2.13	2.06	2.04
2001 Sep-24 to Sep-28	1.99	1.94	1.88	1.90	1.80
2001 Oct- 1 to Oct- 5	1.74	1.83	1.97	2.13	2.11
2001 Oct- 8 to Oct-12	2.02	2.11	2.22	2.41	2.28
2001 Oct-15 to Oct-19	2.26	2.51	2.61	2.39	2.31
2001 Oct-22 to Oct-26	2.61	2.82	2.67	3.15	3.06
2001 Oct-29 to Nov- 2	3.21	3.11	3.07	2.99	2.93
2001 Nov- 5 to Nov- 9	2.87	2.72	2.73	2.68	2.61
2001 Nov-12 to Nov-16	2.45	2.38	2.29	1.99	1.69
2001 Nov-19 to Nov-23	2.08	2.55	1.91		
2001 Nov-26 to Nov-30	1.79	1.87	2.30	2.19	1.83
2001 Dec- 3 to Dec- 7	2.10	2.00	1.89	1.81	2.11
2001 Dec-10 to Dec-14	2.28	2.58	2.57	2.40	2.40
2001 Dec-17 to Dec-21	2.40	2.40	2.40	2.40	2.40
2001 Dec-24 to Dec-28			2.40	2.40	2.40
2001 Dec-31 to Jan- 4	2.40		2.55	2.58	2.58
2002 Jan- 7 to Jan-11	2.58	2.39	2.31	2.32	2.32
2002 Jan-14 to Jan-18	2.32	2.32	2.38	2.40	2.28
2002 Jan-21 to Jan-25		2.28	2.28	2.13	2.03
2002 Jan-28 to Feb- 1	2.03	2.03	2.28	2.28	2.28
2002 Feb- 4 to Feb- 8	2.28	2.28	2.14	2.17	2.21
2002 Feb-11 to Feb-15	2.22	2.39	2.37	2.26	2.18
2002 Feb-18 to Feb-22		2.32	2.41	2.40	2.40
2002 Feb-25 to Mar- 1	2.40	2.46	2.49	2.49	2.51
2002 Mar- 4 to Mar- 8	2.66	2.63	2.52	2.73	2.82
2002 Mar-11 to Mar-15	2.90	2.94	2.97	2.78	2.99
2002 Mar-18 to Mar-22	3.15	3.33	3.29	3.20	3.57
2002 Mar-25 to Mar-29	3.46	3.59	3.35	3.18	
2002 Apr- 1 to Apr- 5	3.43	3.72	3.68	3.56	3.31
2002 Apr- 8 to Apr-12	3.36	3.25	3.25	3.14	3.07
2002 Apr-15 to Apr-19	3.27	3.44	3.40	3.50	3.40
2002 Apr-22 to Apr-26	3.58	3.63	3.53	3.46	3.32
2002 Apr-29 to May- 3	3.44	3.65	3.79	3.65	3.71
2002 May- 6 to May-10	3.61	3.50	3.74	3.72	3.70
2002 May-13 to May-17	3.62	3.75	3.60	3.45	3.41

2002 May-20 to May-24	3.44	3.33	3.39	3.38	3.21
2002 May-27 to May-31		3.18	3.30	3.33	3.15
2002 Jun- 3 to Jun- 7	3.18	3.31	3.29	3.29	3.11
2002 Jun-10 to Jun-14	3.14	3.11	3.15	3.04	3.13
2002 Jun-17 to Jun-21	3.34	3.23	3.24	3.33	3.18
2002 Jun-24 to Jun-28	3.33	3.49	3.92	3.22	3.20
2002 Jul- 1 to Jul- 5	3.28	3.17	3.08		
2002 Jul- 8 to Jul-12	3.06	2.97	3.04	2.85	2.87
2002 Jul-15 to Jul-19	2.83	2.89	2.97	2.85	2.95
2002 Jul-22 to Jul-26	3.01	2.95	2.91	3.05	2.94
2002 Jul-29 to Aug- 2	3.07	2.97	3.02	3.07	2.90
2002 Aug- 5 to Aug- 9	2.81	2.80	2.73	2.75	2.83
2002 Aug-12 to Aug-16	2.91	3.01	3.03	2.92	3.10
2002 Aug-19 to Aug-23	3.10	3.25	3.22	3.36	3.48
2002 Aug-26 to Aug-30	3.51	3.47	3.31	3.25	3.12
2002 Sep- 2 to Sep- 6		3.10	3.13	3.20	3.39
2002 Sep- 9 to Sep-13	3.24	3.35	3.33	3.22	3.37
2002 Sep-16 to Sep-20	3.45	3.46	3.80	3.90	3.95
2002 Sep-23 to Sep-27	3.87	4.00	3.76	3.61	3.76
2002 Sep-30 to Oct- 4	4.09	4.41	4.27	4.23	3.86
2002 Oct- 7 to Oct-11	3.77	3.86	3.91	3.93	3.80
2002 Oct-14 to Oct-18	4.19	4.19	4.10	4.10	4.11
2002 Oct-21 to Oct-25	4.23	4.20	4.24	4.30	4.12
2002 Oct-28 to Nov- 1	4.16	4.20	4.34	4.39	4.07
2002 Nov- 4 to Nov- 8	3.94	3.90	3.92	3.90	3.76
2002 Nov-11 to Nov-15	3.83	3.83	3.83	3.90	3.92
2002 Nov-18 to Nov-22	4.18	4.25	4.27	4.24	4.32
2002 Nov-25 to Nov-29	4.34	4.23	4.19		
2002 Dec- 2 to Dec- 6	4.23	4.35	4.24	4.35	4.39
2002 Dec- 9 to Dec-13	4.32	4.40	4.63	4.81	5.05
2002 Dec-16 to Dec-20	5.31	5.13	4.98	5.14	5.05
2002 Dec-23 to Dec-27	5.03	5.03		4.98	4.81
2002 Dec-30 to Jan- 3	4.74	4.59		4.93	5.13
2003 Jan- 6 to Jan-10	4.94	4.89	5.07	5.05	5.19
2003 Jan-13 to Jan-17	5.23	5.25	5.21	5.50	5.66
2003 Jan-20 to Jan-24		5.47	5.72	6.55	5.91
2003 Jan-27 to Jan-31	5.91	5.52	5.61	5.76	5.58
2003 Feb- 3 to Feb- 7	5.71	6.26	6.22	6.08	6.30
2003 Feb-10 to Feb-14	6.35	6.19	6.19	5.81	5.88
2003 Feb-17 to Feb-21		6.09	6.10	6.38	6.73
2003 Feb-24 to Feb-28	11.98	18.48	10.47	8.42	10.81
2003 Mar- 3 to Mar- 7	8.51	7.71	7.80	7.57	7.42
2003 Mar-10 to Mar-14	6.78	6.25	5.80	5.71	5.17
2003 Mar-17 to Mar-21	5.32	5.13	5.20	5.20	5.05
2003 Mar-24 to Mar-28	5.07	5.07	4.90	4.87	5.06
2003 Mar-31 to Apr- 4	5.01	4.90	4.89	4.91	4.86
2003 Apr- 7 to Apr-11	4.98	5.21	5.11	5.18	5.28
2003 Apr-14 to Apr-18	5.29	5.53	5.62	5.54	
2003 Apr-21 to Apr-25	5.55	5.58	5.58	5.46	5.39
2003 Apr-28 to May- 2	5.30	5.12	5.25	5.32	5.24
2003 May- 5 to May- 9	5.36	5.64	5.49	5.65	5.73
2003 May-12 to May-16	5.91	5.98	6.17	6.24	5.96
2003 May-19 to May-23	6.08	5.93	6.08	6.09	5.92
2003 May-26 to May-30		5.84	5.71	5.76	5.99
2003 Jun- 2 to Jun- 6	6.22	6.25	6.40	6.17	6.25
2003 Jun- 9 to Jun-13	6.25	6.08	6.06	5.86	5.44
2003 Jun-16 to Jun-20	5.45	5.66	5.53	5.53	5.68
2003 Jun-23 to Jun-27	5.89	5.84	5.64	5.49	5.19
2003 Jun-30 to Jul- 4	5.31	5.22	5.05	4.96	
2003 Jul- 7 to Jul-11	5.20	5.40	5.56	5.40	5.22
2003 Jul-14 to Jul-18	5.15	5.17	5.00	4.96	5.01
2003 Jul-21 to Jul-25	5.11	5.04	4.88	4.86	4.68
2003 Jul-28 to Aug- 1	4.68	4.72	4.68	4.63	4.71
2003 Aug- 4 to Aug- 8	4.81	4.71	4.74	4.85	5.02

2003 Aug-11 to Aug-15	5.08	5.06	5.17	5.10	4.83
2003 Aug-18 to Aug-22	4.94	4.99	5.03	5.14	5.24
2003 Aug-25 to Aug-29	5.26	5.09	5.11	4.94	4.86
2003 Sep- 1 to Sep- 5		4.62	4.68	4.70	4.76
2003 Sep- 8 to Sep-12	4.82	4.70	4.78	4.85	4.66
2003 Sep-15 to Sep-19	4.66	4.67	4.61	4.52	4.33
2003 Sep-22 to Sep-26	4.38	4.51	4.58	4.55	4.42
2003 Sep-29 to Oct- 3	4.57	4.66	4.47	4.42	4.34
2003 Oct- 6 to Oct-10	4.40	4.66	4.84	4.78	4.92
2003 Oct-13 to Oct-17	4.96	4.84	4.93	4.92	4.53
2003 Oct-20 to Oct-24	4.30	4.64	4.89	4.90	4.78
2003 Oct-27 to Oct-31	4.56	4.45	4.51	4.40	3.98
2003 Nov- 3 to Nov- 7	4.12	4.01	4.46	4.74	4.48
2003 Nov-10 to Nov-14	4.42	4.52	4.77	4.60	4.62
2003 Nov-17 to Nov-21	4.49	4.35	4.46	4.35	4.15
2003 Nov-24 to Nov-28	4.57	4.49	4.86		
2003 Dec- 1 to Dec- 5	5.02	5.45	5.45	5.70	6.27
2003 Dec- 8 to Dec-12	6.06	6.52	6.67	6.56	6.73
2003 Dec-15 to Dec-19	6.63	6.58	6.56	6.98	6.92
2003 Dec-22 to Dec-26	6.32	5.58	5.50		
2003 Dec-29 to Jan- 2	5.46	5.96	5.76		
2004 Jan- 5 to Jan- 9	6.28	7.04	6.61	6.41	6.91
2004 Jan-12 to Jan-16	6.29	6.26	5.73	6.02	5.43
2004 Jan-19 to Jan-23		6.15	6.26	6.03	5.82
2004 Jan-26 to Jan-30	5.70	5.87	6.04	5.99	5.80
2004 Feb- 2 to Feb- 6	5.51	5.69	5.74	5.54	5.38
2004 Feb- 9 to Feb-13	5.44	5.49	5.34	5.35	5.62
2004 Feb-16 to Feb-20		5.43	5.33	5.28	5.19
2004 Feb-23 to Feb-27	5.10	5.08	5.10	5.13	5.27
2004 Mar- 1 to Mar- 5	5.17	5.37	5.34	5.17	5.32
2004 Mar- 8 to Mar-12	5.42	5.34	5.33	5.33	5.52
2004 Mar-15 to Mar-19	5.59	5.60	5.61	5.63	5.49
2004 Mar-22 to Mar-26	5.46	5.36	5.35	5.22	5.16
2004 Mar-29 to Apr- 2	5.25	5.40	5.63	5.82	5.69
2004 Apr- 5 to Apr- 9	5.81	5.70	5.76	5.84	
2004 Apr-12 to Apr-16	5.85	5.92	5.73	5.68	5.62
2004 Apr-19 to Apr-23	5.57	5.46	5.52	5.59	5.53
2004 Apr-26 to Apr-30	5.60	5.81	5.80	5.78	5.81
2004 May- 3 to May- 7	5.80	6.21	6.09	6.22	6.18
2004 May-10 to May-14	6.14	6.24	6.41	6.42	6.43
2004 May-17 to May-21	6.41	6.28	6.18	6.44	6.35
2004 May-24 to May-28	6.48	6.73	6.70	6.51	6.45
2004 May-31 to Jun- 4		6.45	6.51	6.44	6.15
2004 Jun- 7 to Jun-11	6.09	6.19	6.04	6.00	
2004 Jun-14 to Jun-18	6.15	6.35	6.38	6.57	6.48
2004 Jun-21 to Jun-25	6.42	6.29	6.30	6.41	6.28
2004 Jun-28 to Jul- 2	6.13	6.02	6.03	5.95	5.88
2004 Jul- 5 to Jul- 9		6.16	6.27	6.19	5.89
2004 Jul-12 to Jul-16	5.95	5.85	5.91	5.92	5.77
2004 Jul-19 to Jul-23	5.75	5.80	5.90	5.85	5.98
2004 Jul-26 to Jul-30	5.94	5.87	5.77	5.93	6.03
2004 Aug- 2 to Aug- 6	5.86	5.77	5.70	5.54	5.42
2004 Aug- 9 to Aug-13	5.58	5.78	5.64	5.46	5.27
2004 Aug-16 to Aug-20	5.34	5.27	5.36	5.34	5.39
2004 Aug-23 to Aug-27	5.34	5.23	5.32	5.19	5.05
2004 Aug-30 to Sep- 3	5.05	5.04	5.02	4.75	4.32
2004 Sep- 6 to Sep-10		4.41	4.69	4.57	4.57
2004 Sep-13 to Sep-17	5.12	5.15	5.17	4.82	4.95
2004 Sep-20 to Sep-24	5.22	5.43	5.58	5.58	5.41
2004 Sep-27 to Oct- 1	5.22	5.45	6.26	6.36	5.38
2004 Oct- 4 to Oct- 8	5.72	6.07	6.00	6.24	5.59
2004 Oct-11 to Oct-15	5.63	5.63	5.38	5.76	5.64
2004 Oct-18 to Oct-22	5.64	6.13	7.27	7.35	7.11
2004 Oct-25 to Oct-29	7.75	7.78	8.12	6.80	6.43

2004 Nov- 1 to Nov- 5	6.98	6.88	7.25	7.40	6.08
2004 Nov- 8 to Nov-12	6.62	5.79	6.12	6.19	5.90
2004 Nov-15 to Nov-19	6.02	6.57	6.06	5.59	4.81
2004 Nov-22 to Nov-26	5.24	5.24	5.01		
2004 Nov-29 to Dec- 3	6.76	6.79	6.78	6.69	6.04
2004 Dec- 6 to Dec-10	6.05	6.03	5.98	6.04	6.29
2004 Dec-13 to Dec-17	6.89	7.10	7.04	6.88	7.26
2004 Dec-20 to Dec-24	7.14	6.83	7.05	6.98	
2004 Dec-27 to Dec-31	6.57	6.27	6.18	6.02	
2005 Jan- 3 to Jan- 7	5.53	5.71	5.84	5.79	5.82
2005 Jan-10 to Jan-14	6.21	5.96	5.89	6.06	6.45
2005 Jan-17 to Jan-21		6.69	6.19	6.27	6.43
2005 Jan-24 to Jan-28	6.41	6.44	6.44	6.50	6.23
2005 Jan-31 to Feb- 4	6.14	6.28	6.38	6.32	6.12
2005 Feb- 7 to Feb-11	6.02	5.95	6.20	6.21	6.02
2005 Feb-14 to Feb-18	5.95	6.01	6.10	6.05	5.88
2005 Feb-21 to Feb-25		5.92	6.02	6.33	6.24
2005 Feb-28 to Mar- 4	6.62	6.63	6.61	6.71	6.51
2005 Mar- 7 to Mar-11	6.66	6.81	6.99	6.91	6.73
2005 Mar-14 to Mar-18	6.86	7.16	7.08	7.25	7.12
2005 Mar-21 to Mar-25	7.16	7.24	7.11	7.07	
2005 Mar-28 to Apr- 1	6.94	6.93	7.18	7.46	7.57
2005 Apr- 4 to Apr- 8	7.80	7.44	7.46	7.50	7.26
2005 Apr-11 to Apr-15	7.17	7.34	7.07	7.02	6.95
2005 Apr-18 to Apr-22	6.95	6.95	7.10	6.93	7.06
2005 Apr-25 to Apr-29	7.27	7.08	7.10	6.67	6.64
2005 May- 2 to May- 6	6.50	6.61	6.49	6.65	6.67
2005 May- 9 to May-13	6.56	6.67	6.63	6.62	6.47
2005 May-16 to May-20	6.45	6.41	6.50	6.39	6.36
2005 May-23 to May-27	6.33	6.45	6.33	6.30	6.22
2005 May-30 to Jun- 3		6.31	6.36	6.63	6.65
2005 Jun- 6 to Jun-10	7.05	7.13	7.22	7.05	7.09
2005 Jun-13 to Jun-17	7.08	7.32	7.39	7.41	7.61
2005 Jun-20 to Jun-24	7.80	7.46	7.39	7.51	7.45
2005 Jun-27 to Jul- 1	7.29	7.04	7.08	7.01	7.01
2005 Jul- 4 to Jul- 8		7.38	7.69	7.62	7.87
2005 Jul-11 to Jul-15	7.35	7.79	7.78	7.99	8.02
2005 Jul-18 to Jul-22	7.77	7.70	7.75	7.64	7.41
2005 Jul-25 to Jul-29	7.38	7.45	7.52	7.69	7.76
2005 Aug- 1 to Aug- 5	8.03	8.38	8.75	8.55	8.60
2005 Aug- 8 to Aug-12	8.93	8.70	8.82	9.29	9.59
2005 Aug-15 to Aug-19	9.53	9.66	9.99	9.38	9.09
2005 Aug-22 to Aug-26	9.44	9.96	10.02	9.77	9.86
2005 Aug-29 to Sep- 2	9.86	12.36	12.69	11.36	11.75
2005 Sep- 5 to Sep- 9		11.56	11.03	10.92	11.03
2005 Sep-12 to Sep-16	10.68	10.71	10.80	11.24	11.25
2005 Sep-19 to Sep-23	11.99	12.76	14.26	14.84	
2005 Oct- 3 to Oct- 7					13.67
2005 Oct-10 to Oct-14	13.29	13.67	13.77	13.48	12.80
2005 Oct-17 to Oct-21	13.89	13.41	13.52	13.24	12.73
2005 Oct-24 to Oct-28	12.95	13.90	14.68	13.90	13.10
2005 Oct-31 to Nov- 4	12.18	10.80	10.85	10.79	9.67
2005 Nov- 7 to Nov-11	8.77	9.15	9.31	9.66	9.20
2005 Nov-14 to Nov-18	9.15	9.21	11.03	11.92	10.01
2005 Nov-21 to Nov-25	10.48	11.15	11.02		
2005 Nov-28 to Dec- 2	11.01	11.17	11.73	12.58	12.95
2005 Dec- 5 to Dec- 9	14.27	13.57	13.95	14.25	15.02
2005 Dec-12 to Dec-16	14.82	15.39	14.81	14.07	13.36
2005 Dec-19 to Dec-23	13.73	13.79	13.56	13.03	11.17
2005 Dec-26 to Dec-30		10.22	9.90	10.07	9.52
2006 Jan- 2 to Jan- 6		9.90	9.25	9.24	9.30
2006 Jan- 9 to Jan-13	8.79	8.60	8.55	8.70	8.50
2006 Jan-16 to Jan-20		8.82	8.86	8.21	8.80
2006 Jan-23 to Jan-27	8.29	8.27	8.50	7.86	8.19

2006 Jan-30 to Feb- 3	8.36	8.73	8.71	8.01	8.01
2006 Feb- 6 to Feb-10	8.24	7.74	7.88	7.55	7.57
2006 Feb-13 to Feb-17	7.36	7.03	7.31	7.16	7.39
2006 Feb-20 to Feb-24		7.40	7.55	7.23	7.39
2006 Feb-27 to Mar- 3	6.97	6.69	6.62	6.69	6.59
2006 Mar- 6 to Mar-10	6.50	6.53	6.47	6.31	6.40
2006 Mar-13 to Mar-17	6.77	7.15	7.10	7.12	7.17
2006 Mar-20 to Mar-24	7.00	6.83	7.06	7.16	7.43
2006 Mar-27 to Mar-31	7.05	7.15	7.16	7.19	6.98
2006 Apr- 3 to Apr- 7	7.08	7.04	6.89	7.06	6.81
2006 Apr-10 to Apr-14	6.83	6.99	6.78	6.64	
2006 Apr-17 to Apr-21	7.22	7.60	7.72	7.95	7.65
2006 Apr-24 to Apr-28	7.73	7.37	7.17	6.94	6.64
2006 May- 1 to May- 5	6.53	6.68	6.56	6.47	6.80
2006 May- 8 to May-12	6.54	6.55	6.50	6.80	6.35
2006 May-15 to May-19	5.92	5.99	6.15	5.79	5.77
2006 May-22 to May-26	5.91	6.27	6.01	5.85	5.78
2006 May-29 to Jun- 2		6.20	5.97	6.25	6.23
2006 Jun- 5 to Jun- 9	6.40	6.16	5.82	5.84	6.10
2006 Jun-12 to Jun-16	6.02	5.95	6.08	6.43	7.03
2006 Jun-19 to Jun-23	6.71	6.62	6.50	6.51	6.14
2006 Jun-26 to Jun-30	5.89	5.97	6.04	6.09	5.84
2006 Jul- 3 to Jul- 7			5.70	5.28	5.18
2006 Jul-10 to Jul-14	5.32	5.51	5.66	5.92	6.28
2006 Jul-17 to Jul-21	6.27	6.02	5.89	6.14	5.90
2006 Jul-24 to Jul-28	6.33	6.78	6.71	7.03	7.24
2006 Jul-31 to Aug- 4	8.04	8.66	8.65	7.61	7.44
2006 Aug- 7 to Aug-11	6.97	7.06	7.60	7.95	7.56
2006 Aug-14 to Aug-18	6.89	6.90	7.01	6.73	6.66
2006 Aug-21 to Aug-25	6.72	6.86	7.19	7.22	7.48
2006 Aug-28 to Sep- 1	6.51	6.24	6.40	5.80	5.24
2006 Sep- 4 to Sep- 8		5.45	5.70	5.64	5.31
2006 Sep-11 to Sep-15	5.29	5.57	5.40	5.09	4.40
2006 Sep-18 to Sep-22	5.02	4.99	4.87	4.65	4.47
2006 Sep-25 to Sep-29	4.31	4.36	4.35	4.15	3.66
2006 Oct- 2 to Oct- 6	4.11	4.01	4.38	4.69	4.41
2006 Oct- 9 to Oct-13	5.06	5.16	5.66	5.17	4.30
2006 Oct-16 to Oct-20	5.13	6.26	6.07	6.77	6.88
2006 Oct-23 to Oct-27	7.29	7.13	7.20	7.91	7.41
2006 Oct-30 to Nov- 3	6.99	6.64	7.15	7.32	7.43
2006 Nov- 6 to Nov-10	6.72	6.59	7.39	7.35	7.16
2006 Nov-13 to Nov-17	7.26	7.42	7.45	7.59	7.23
2006 Nov-20 to Nov-24	7.79	7.57	7.42		
2006 Nov-27 to Dec- 1	7.58	7.61	7.74	8.32	8.42
2006 Dec- 4 to Dec- 8	7.84	7.32	7.32	7.61	7.45
2006 Dec-11 to Dec-15	6.81	6.93	7.21	7.26	6.82
2006 Dec-18 to Dec-22	6.62	6.27	6.43	6.09	5.88
2006 Dec-25 to Dec-29		5.72	5.54	5.63	5.50
2007 Jan- 1 to Jan- 5		5.40	5.47	5.60	5.52
2007 Jan- 8 to Jan-12	6.02	6.15	6.42	6.09	5.97
2007 Jan-15 to Jan-19		6.82	6.57	6.29	6.40
2007 Jan-22 to Jan-26	7.20	7.53	7.58	7.18	6.95
2007 Jan-29 to Feb- 2	7.35	7.32	7.76	7.93	8.17
2007 Feb- 5 to Feb- 9	9.14	8.29	7.90	8.06	8.16
2007 Feb-12 to Feb-16	7.78	8.09	8.90	8.91	8.45
2007 Feb-19 to Feb-23		7.34	7.51	7.47	7.53
2007 Feb-26 to Mar- 2	7.73	7.44	7.23	7.07	7.22
2007 Mar- 5 to Mar- 9	7.36	7.55	7.50	7.14	7.05
2007 Mar-12 to Mar-16	6.81	6.78	6.86	7.02	6.84
2007 Mar-19 to Mar-23	6.70	6.81	6.82	7.07	7.16
2007 Mar-26 to Mar-30	7.15	7.15	7.47	7.34	7.50
2007 Apr- 2 to Apr- 6	7.62	7.57	7.46	7.53	
2007 Apr- 9 to Apr-13	7.65	7.65	7.97	7.95	7.93
2007 Apr-16 to Apr-20	7.66	7.50	7.54	7.54	7.32

2007 Apr-23 to Apr-27	7.24	7.57	7.60	7.56	7.44
2007 Apr-30 to May- 4	7.71	7.64	7.64	7.58	7.82
2007 May- 7 to May-11	7.69	7.50	7.46	7.63	7.53
2007 May-14 to May-18	7.85	7.68	7.62	7.69	7.87
2007 May-21 to May-25	7.66	7.60	7.51	7.56	7.47
2007 May-28 to Jun- 1		7.51	7.71	7.80	7.57
2007 Jun- 4 to Jun- 8	7.73	7.83	7.83	7.89	7.52
2007 Jun-11 to Jun-15	7.42	7.45	7.60	7.48	7.58
2007 Jun-18 to Jun-22	7.69	7.46	7.39	7.24	7.04
2007 Jun-25 to Jun-29	6.77	6.85	6.74	6.79	6.40
2007 Jul- 2 to Jul- 6	6.24	6.37		6.30	6.15
2007 Jul- 9 to Jul-13	6.39	6.44	6.66	6.26	6.27
2007 Jul-16 to Jul-20	6.32	6.34	6.23	6.50	6.46
2007 Jul-23 to Jul-27	6.00	5.66	5.56	5.83	5.77
2007 Jul-30 to Aug- 3	6.31	6.53	6.19	6.34	6.11
2007 Aug- 6 to Aug-10	6.10	6.38	6.24	6.45	6.57
2007 Aug-13 to Aug-17	7.15	6.86	7.30	6.96	7.14
2007 Aug-20 to Aug-24	6.47	5.92	5.84	5.73	5.69
2007 Aug-27 to Aug-31	5.34	5.56	5.64	5.54	5.49
2007 Sep- 3 to Sep- 7		5.30	5.80	6.02	5.53
2007 Sep-10 to Sep-14	5.56	5.98	6.13	6.27	6.23
2007 Sep-17 to Sep-21	6.38	6.42	6.25	6.02	5.96
2007 Sep-24 to Sep-28	6.12	6.54	6.47	6.38	6.15
2007 Oct- 1 to Oct- 5	6.07	6.55	6.96	6.91	6.77
2007 Oct- 8 to Oct-12	6.69	6.63	6.79	6.85	6.46
2007 Oct-15 to Oct-19	7.09	7.29	7.12	7.11	6.91
2007 Oct-22 to Oct-26	6.63	6.30	6.11	6.49	6.43
2007 Oct-29 to Nov- 2	6.66	6.99	7.28	7.09	6.63
2007 Nov- 5 to Nov- 9	6.71	7.20	7.42	6.81	6.59
2007 Nov-12 to Nov-16	6.83	7.22	7.28	7.35	7.29
2007 Nov-19 to Nov-23	7.38	6.81	6.67		6.67
2007 Nov-26 to Nov-30	7.53	7.42	7.51	7.45	7.29
2007 Dec- 3 to Dec- 7	6.97	7.27	7.04	7.29	7.04
2007 Dec-10 to Dec-14	6.98	7.12	7.22	7.46	7.09
2007 Dec-17 to Dec-21	7.06	7.16	7.18	7.19	7.03
2007 Dec-24 to Dec-28	7.03		6.94	6.80	7.11
2007 Dec-31 to Jan- 4	7.11		7.83	7.84	7.51
2008 Jan- 7 to Jan-11	7.61	7.59	7.89	7.96	8.13
2008 Jan-14 to Jan-18	8.45	8.43	8.23	8.10	8.42
2008 Jan-21 to Jan-25		7.97	7.84	7.85	7.80
2008 Jan-28 to Feb- 1	7.87	8.10	8.17	8.10	7.88
2008 Feb- 4 to Feb- 8	7.56	7.80	7.94	7.99	8.06
2008 Feb-11 to Feb-15	8.38	8.37	8.35	8.50	8.73
2008 Feb-18 to Feb-22		8.91	9.08	8.90	8.65
2008 Feb-25 to Feb-29	9.15	9.21	9.21	9.11	9.10
2008 Mar- 3 to Mar- 7	9.07	9.21	9.37	9.70	9.82
2008 Mar-10 to Mar-14	9.59	9.85	9.69	9.74	9.84
2008 Mar-17 to Mar-21	9.59	9.10	9.11	8.54	
2008 Mar-24 to Mar-28	8.99	9.28	9.25	9.30	9.36
2008 Mar-31 to Apr- 4	9.86	9.92	9.60	9.68	9.36
2008 Apr- 7 to Apr-11	9.48	9.78	9.88	10.18	10.07
2008 Apr-14 to Apr-18	10.03	10.16	10.11	10.27	10.08
2008 Apr-21 to Apr-25	10.50	10.56	10.33	10.58	10.72
2008 Apr-28 to May- 2	10.95	10.94	10.81	10.66	10.37
2008 May- 5 to May- 9	10.77	11.09	11.08	11.33	11.29
2008 May-12 to May-16	11.38	11.18	11.52	11.41	11.31
2008 May-19 to May-23	11.10	10.94	11.40	11.57	11.56
2008 May-26 to May-30		11.85	11.60	11.81	11.43
2008 Jun- 2 to Jun- 6	11.80	12.27	12.17	12.49	12.71
2008 Jun- 9 to Jun-13	12.71	12.72	12.49	12.51	12.51
2008 Jun-16 to Jun-20	12.73	12.87	12.93	13.09	12.76
2008 Jun-23 to Jun-27	12.92	12.96	12.76	12.70	13.10
2008 Jun-30 to Jul- 4	13.19	13.28	13.31	13.00	
2008 Jul- 7 to Jul-11	12.96	12.47	12.10	11.83	12.15
2008 Jul-14 to Jul-18	11.58	11.79	11.15	11.43	10.54

2008 Jul-21 to Jul-25	10.58	10.16	9.88	9.70	9.34
2008 Jul-28 to Aug- 1	9.26	9.17	9.01	9.26	9.05
2008 Aug- 4 to Aug- 8	9.20	8.66	8.70	8.77	8.22
2008 Aug-11 to Aug-15	8.18	8.23	8.11	8.15	7.82
2008 Aug-18 to Aug-22	7.74	7.73	8.02	8.04	7.98
2008 Aug-25 to Aug-29	7.63	8.02	8.54	8.36	8.24
2008 Sep- 1 to Sep- 5		8.24	7.26	7.24	7.40
2008 Sep- 8 to Sep-12	7.68	7.28	7.65	7.83	8.02
2008 Sep-15 to Sep-19	8.02	7.76	7.72	8.26	7.79
2008 Sep-22 to Sep-26	7.66	7.84	8.15	7.63	7.42
2008 Sep-29 to Oct- 3	7.13	7.17	7.41	7.64	7.16
2008 Oct- 6 to Oct-10	6.87	6.74	6.58	6.69	6.52
2008 Oct-13 to Oct-17	6.62	6.74	6.64	6.65	6.76
2008 Oct-20 to Oct-24	6.98	6.76	6.94	6.77	6.29
2008 Oct-27 to Oct-31	6.27	6.40	6.58	6.75	6.18
2008 Nov- 3 to Nov- 7	6.45	6.79	6.94	7.04	6.60
2008 Nov-10 to Nov-14	7.07	7.02	6.65	6.31	6.33
2008 Nov-17 to Nov-21	6.55	6.74	6.76	6.76	6.56
2008 Nov-24 to Nov-28	6.85	6.71	6.43		6.43
2008 Dec- 1 to Dec- 5	6.48	6.68	6.48	6.55	5.99
2008 Dec- 8 to Dec-12	5.73	5.57	5.67	5.86	5.56
2008 Dec-15 to Dec-19	5.75	5.75	5.79	5.63	5.66
2008 Dec-22 to Dec-26	5.39	5.37	5.44		5.44
2008 Dec-29 to Jan- 2	5.81	5.71	5.63		5.41
2009 Jan- 5 to Jan- 9	5.83	6.10	5.89	5.96	5.60
2009 Jan-12 to Jan-16	5.59	5.70	5.47	5.27	5.09
2009 Jan-19 to Jan-23		4.86	4.87	4.72	4.75
2009 Jan-26 to Jan-30	4.62	4.76	4.84	4.71	4.77
2009 Feb- 2 to Feb- 6	4.48	5.04	5.01	4.84	4.67
2009 Feb- 9 to Feb-13	4.76	4.84	4.68	4.73	4.60
2009 Feb-16 to Feb-20		4.35	4.35	4.46	4.21
2009 Feb-23 to Feb-27	4.23	4.21	4.20	4.08	4.04
2009 Mar- 2 to Mar- 6	4.36	4.43	4.23	4.22	3.93
2009 Mar- 9 to Mar-13	3.86	3.88	3.92	3.87	3.90
2009 Mar-16 to Mar-20	3.78	3.78	3.75	3.68	3.99
2009 Mar-23 to Mar-27	4.17	4.13	4.13	4.16	3.73
2009 Mar-30 to Apr- 3	3.63	3.58	3.56	3.69	3.66
2009 Apr- 6 to Apr-10	3.74	3.60	3.50	3.59	
2009 Apr-13 to Apr-17	3.46	3.59	3.60	3.54	3.47
2009 Apr-20 to Apr-24	3.55	3.43	3.48	3.46	3.31
2009 Apr-27 to May- 1	3.19	3.29	3.43	3.25	3.30
2009 May- 4 to May- 8	3.47	3.62	3.67	3.96	4.16
2009 May-11 to May-15	4.24	4.41	4.42	4.10	4.05
2009 May-18 to May-22	4.02	3.99	3.75	3.77	3.41
2009 May-25 to May-29		3.35	3.49	3.55	3.92
2009 Jun- 1 to Jun- 5	3.86	4.05	3.81	3.58	3.51
2009 Jun- 8 to Jun-12	3.53	3.53	3.56	3.51	3.54
2009 Jun-15 to Jun-19	3.80	4.16	3.99	4.19	4.04
2009 Jun-22 to Jun-26	4.01	3.91	3.80	3.82	3.81
2009 Jun-29 to Jul- 3	3.88	3.72	3.63	3.49	
2009 Jul- 6 to Jul-10	3.24	3.30	3.22	3.36	3.24
2009 Jul-13 to Jul-17	3.17	3.29	3.37	3.21	3.39
2009 Jul-20 to Jul-24	3.49	3.48	3.49	3.66	3.37
2009 Jul-27 to Jul-31	3.46	3.49	3.41	3.34	3.34
2009 Aug- 3 to Aug- 7	3.43	3.53	3.61	3.78	3.57
2009 Aug-10 to Aug-14	3.55	3.54	3.36	3.34	3.18
2009 Aug-17 to Aug-21	3.11	3.12	3.03	3.03	2.78
2009 Aug-24 to Aug-28	2.69	2.85	2.76	2.76	2.52
2009 Aug-31 to Sep- 4	2.42	2.36	2.25	2.06	1.83
2009 Sep- 7 to Sep-11		2.43	2.72	2.68	2.94
2009 Sep-14 to Sep-18	2.84	3.21	3.28	3.50	3.21
2009 Sep-21 to Sep-25	3.35	3.37	3.43	3.56	3.61
2009 Sep-28 to Oct- 2	3.54	3.30	3.25	2.91	2.32
2009 Oct- 5 to Oct- 9	2.89	3.23	3.70	4.24	3.92

2009 Oct-12 to Oct-16	3.96	4.03	3.82	3.88	3.94
2009 Oct-19 to Oct-23	4.22	4.60	4.80	4.98	4.88
2009 Oct-26 to Oct-30	4.52	4.52	4.59	4.11	4.11
2009 Nov- 2 to Nov- 6	4.32	4.33	4.49	4.30	3.95
2009 Nov- 9 to Nov-13	3.78	3.76	3.59	3.24	2.51
2009 Nov-16 to Nov-20	2.65	3.47	3.74	3.57	3.09
2009 Nov-23 to Nov-27	3.79	3.63	3.32		3.32
2009 Nov-30 to Dec- 4	4.41	4.30	4.67	4.57	4.53
2009 Dec- 7 to Dec-11	4.78	5.10	5.27	5.02	5.21
2009 Dec-14 to Dec-18	5.41	5.53	5.57	5.65	5.87
2009 Dec-21 to Dec-25	5.79	5.56	5.55	5.75	
2009 Dec-28 to Jan- 1	5.91	6.01	5.78	5.82	
2010 Jan- 4 to Jan- 8	6.09	6.19	6.47	7.51	6.56
2010 Jan-11 to Jan-15	5.77	5.57	5.61	5.77	5.66
2010 Jan-18 to Jan-22		5.51	5.54	5.52	5.67
2010 Jan-25 to Jan-29	5.76	5.61	5.42	5.32	5.26
2010 Feb- 1 to Feb- 5	5.30	5.47	5.51	5.47	5.61
2010 Feb- 8 to Feb-12	5.73	5.54	5.48	5.53	5.48
2010 Feb-15 to Feb-19		5.65	5.47	5.40	5.10
2010 Feb-22 to Feb-26	4.92	4.91	4.91	4.84	4.76
2010 Mar- 1 to Mar- 5	4.83	4.78	4.76	4.78	4.56
2010 Mar- 8 to Mar-12	4.47	4.51	4.44	4.47	4.35
2010 Mar-15 to Mar-19	4.29	4.38	4.27	4.19	4.01
2010 Mar-22 to Mar-26	4.02	4.08	4.02	4.01	3.92
2010 Mar-29 to Apr- 2	3.83	3.79	3.93	3.72	
2010 Apr- 5 to Apr- 9	3.93	4.16	4.08	3.92	3.90
2010 Apr-12 to Apr-16	4.04	3.97	4.15	4.16	3.97
2010 Apr-19 to Apr-23	4.02	3.93	3.96	3.95	4.07
2010 Apr-26 to Apr-30	4.23	4.18	4.19	4.24	3.94
2010 May- 3 to May- 7	3.86	3.96	4.00	3.97	3.91
2010 May-10 to May-14	4.08	4.15	4.18	4.26	4.27
2010 May-17 to May-21	4.34	4.42	4.28	4.12	4.12
2010 May-24 to May-28	4.08	4.08	4.19	4.22	4.31
2010 May-31 to Jun- 4		4.39	4.32	4.46	4.60
2010 Jun- 7 to Jun-11	4.67	4.89	4.75	4.68	4.68
2010 Jun-14 to Jun-18	4.94	5.11	5.13	5.14	5.17
2010 Jun-21 to Jun-25	5.15	4.87	4.90	4.88	4.84
2010 Jun-28 to Jul- 2	4.85	4.68	4.53	4.54	4.72
2010 Jul- 5 to Jul- 9		4.85	4.76	4.61	4.36
2010 Jul-12 to Jul-16	4.42	4.46	4.39	4.43	4.68
2010 Jul-19 to Jul-23	4.56	4.59	4.70	4.67	4.69
2010 Jul-26 to Jul-30	4.65	4.72	4.75	4.80	4.81
2010 Aug- 2 to Aug- 6	4.94	4.78	4.77	4.84	4.67
2010 Aug- 9 to Aug-13	4.52	4.43	4.38	4.42	4.35
2010 Aug-16 to Aug-20	4.37	4.28	4.35	4.29	4.19
2010 Aug-23 to Aug-27	4.12	4.07	3.99	3.85	3.75
2010 Aug-30 to Sep- 3	3.77	3.80	3.73	3.74	3.74
2010 Sep- 6 to Sep-10		3.82	3.81	3.79	3.79
2010 Sep-13 to Sep-17	3.83	3.98	4.06	4.09	4.11
2010 Sep-20 to Sep-24	4.01	3.95	4.02	4.08	3.97
2010 Sep-27 to Oct- 1	3.80	3.80	3.81	3.85	3.67
2010 Oct- 4 to Oct- 8	3.56	3.51	3.56	3.62	3.36
2010 Oct-11 to Oct-15	3.43	3.40	3.58	3.58	3.47
2010 Oct-18 to Oct-22	3.36	3.36	3.46	3.46	3.19
2010 Oct-25 to Oct-29	3.18	3.28	3.37	3.36	3.36
2010 Nov- 1 to Nov- 5	3.42	3.20	3.35	3.53	3.47
2010 Nov- 8 to Nov-12	3.49	3.76	4.00	3.73	3.50
2010 Nov-15 to Nov-19	3.56	3.66	3.77	3.89	3.79
2010 Nov-22 to Nov-26	4.02	3.93	3.82		3.82
2010 Nov-29 to Dec- 3	4.12	4.16	4.21	4.28	4.23
2010 Dec- 6 to Dec-10	4.47	4.48	4.47	4.52	4.37
2010 Dec-13 to Dec-17	4.55	4.35	4.22	4.19	3.99
2010 Dec-20 to Dec-24	4.10	4.17	4.01	4.08	
2010 Dec-27 to Dec-31	4.05	4.10	4.19	4.22	4.22
2011 Jan- 3 to Jan- 7	4.54	4.61	4.52	4.49	4.42

2011 Jan-10 to Jan-14	4.49	4.42	4.55	4.48	4.38
2011 Jan-17 to Jan-21		4.52	4.48	4.57	4.72
2011 Jan-24 to Jan-28	4.72	4.46	4.40	4.41	4.27
2011 Jan-31 to Feb- 4	4.42	4.42	4.55	4.69	4.48
2011 Feb- 7 to Feb-11	4.32	4.24	4.22	4.11	3.96
2011 Feb-14 to Feb-18	3.89	3.92	3.93	3.90	3.84
2011 Feb-21 to Feb-25		3.89	3.83	3.83	3.81
2011 Feb-28 to Mar- 4	3.93	3.93	3.79	3.75	3.70
2011 Mar- 7 to Mar-11	3.73	3.83	3.81	3.87	3.78
2011 Mar-14 to Mar-18	3.90	3.81	3.86	3.85	3.98
2011 Mar-21 to Mar-25	3.99	4.05	4.18	4.27	4.13
2011 Mar-28 to Apr- 1	4.35	4.27	4.25	4.32	4.32
2011 Apr- 4 to Apr- 8	4.21	4.22	4.17	4.12	4.05
2011 Apr-11 to Apr-15	4.05	4.08	4.14	4.12	4.21
2011 Apr-18 to Apr-22	4.23	4.19	4.33	4.33	
2011 Apr-25 to Apr-29	4.37	4.32	4.35	4.38	4.51
2011 May- 2 to May- 6	4.60	4.60	4.59	4.49	4.24
2011 May- 9 to May-13	4.28	4.19	4.23	4.10	4.09
2011 May-16 to May-20	4.21	4.25	4.15	4.10	4.05
2011 May-23 to May-27	4.27	4.37	4.36	4.37	4.36
2011 May-30 to Jun- 3		4.63	4.62	4.64	4.72
2011 Jun- 6 to Jun-10	4.83	4.83	4.83	4.92	4.72
2011 Jun-13 to Jun-17	4.75	4.59	4.53	4.54	4.39
2011 Jun-20 to Jun-24	4.33	4.37	4.42	4.31	4.20
2011 Jun-27 to Jul- 1	4.25	4.34	4.40	4.28	4.33
2011 Jul- 4 to Jul- 8		4.40	4.34	4.25	4.19
2011 Jul-11 to Jul-15	4.35	4.38	4.43	4.42	4.49
2011 Jul-18 to Jul-22	4.60	4.60	4.64	4.58	4.46
2011 Jul-25 to Jul-29	4.45	4.43	4.46	4.41	4.26
2011 Aug- 1 to Aug- 5	4.29	4.30	4.26	4.20	4.00
2011 Aug- 8 to Aug-12	4.00	4.06	4.09	4.06	4.17
2011 Aug-15 to Aug-19	4.05	4.03	3.98	3.98	3.99
2011 Aug-22 to Aug-26	3.97	4.01	4.10	4.01	3.96
2011 Aug-29 to Sep- 2	3.93	3.85	3.97	4.18	4.12
2011 Sep- 5 to Sep- 9		3.93	3.96	3.99	3.96
2011 Sep-12 to Sep-16	3.92	3.96	4.01	4.04	3.84
2011 Sep-19 to Sep-23	3.78	3.84	3.78	3.72	3.74
2011 Sep-26 to Sep-30	3.80	3.92	3.88	3.77	3.68
2011 Oct- 3 to Oct- 7	3.57	3.56	3.63	3.49	3.40
2011 Oct-10 to Oct-14	3.41	3.52	3.54	3.42	3.49
2011 Oct-17 to Oct-21	3.72	3.63	3.59	3.61	3.54
2011 Oct-24 to Oct-28	3.61	3.62	3.65	3.59	3.63
2011 Oct-31 to Nov- 4	3.66	3.49	3.39	3.39	3.44
2011 Nov- 7 to Nov-11	3.35	3.42	3.55	3.48	3.29
2011 Nov-14 to Nov-18	3.17	3.12	3.11	3.11	3.01
2011 Nov-21 to Nov-25	2.94	3.06	2.84		2.84
2011 Nov-28 to Dec- 2	3.09	3.39	3.53	3.49	3.35
2011 Dec- 5 to Dec- 9	3.38	3.43	3.45	3.42	3.29
2011 Dec-12 to Dec-16	3.13	3.12	3.08	3.05	3.01
2011 Dec-19 to Dec-23	3.03	3.06	3.05	3.08	2.97
2011 Dec-26 to Dec-30		3.09	3.07	3.03	2.98
2012 Jan- 2 to Jan- 6		2.97	2.96	2.91	2.85
2012 Jan- 9 to Jan-13	2.89	2.97	2.81	2.70	2.67
2012 Jan-16 to Jan-20		2.51	2.49	2.36	2.23
2012 Jan-23 to Jan-27	2.39	2.60	2.61	2.68	2.59
2012 Jan-30 to Feb- 3	2.71	2.51	2.32	2.30	2.40
2012 Feb- 6 to Feb-10	2.46	2.60	2.48	2.50	2.51
2012 Feb-13 to Feb-17	2.42	2.48	2.54	2.47	2.67
2012 Feb-20 to Feb-24		2.63	2.60	2.68	2.60
2012 Feb-27 to Mar- 2	2.55	2.44	2.44	2.45	2.38
2012 Mar- 5 to Mar- 9	2.31	2.30	2.24	2.24	2.21
2012 Mar-12 to Mar-16	2.17	2.15	2.13	2.07	2.01
2012 Mar-19 to Mar-23	2.14	2.19	2.21	2.19	2.07
2012 Mar-26 to Mar-30	2.16	2.09	2.05	2.02	2.00
2012 Apr- 2 to Apr- 6	1.88	1.94	2.06	1.98	

2012 Apr- 9 to Apr-13	1.99	1.99	1.91	1.87	1.87
2012 Apr-16 to Apr-20	1.88	1.89	1.87	1.85	1.82
2012 Apr-23 to Apr-27	1.89	1.97	1.99	2.10	2.05
2012 Apr-30 to May- 4	2.10	2.29	2.31	2.29	2.30
2012 May- 7 to May-11	2.30	2.27	2.36	2.36	2.37
2012 May-14 to May-18	2.41	2.38	2.50	2.60	2.56
2012 May-21 to May-25	2.60	2.55	2.60	2.66	2.56
2012 May-28 to Jun- 1		2.50	2.39	2.34	2.24
2012 Jun- 4 to Jun- 8	2.32	2.39	2.41	2.33	2.22
2012 Jun-11 to Jun-15	2.22	2.17	2.18	2.20	2.44
2012 Jun-18 to Jun-22	2.45	2.59	2.60	2.48	2.50
2012 Jun-25 to Jun-29	2.70	2.70	2.87	2.81	2.74
2012 Jul- 2 to Jul- 6	2.73	2.78		2.90	2.94
2012 Jul- 9 to Jul-13	2.79	2.87	2.72	2.83	2.88
2012 Jul-16 to Jul-20	2.92	2.83	2.84	2.99	3.03
2012 Jul-23 to Jul-27	3.05	3.16	3.19	3.13	3.10
2012 Jul-30 to Aug- 3	3.14	3.20	3.20	3.16	2.91
2012 Aug- 6 to Aug-10	2.90	2.99	2.97	2.89	2.84
2012 Aug-13 to Aug-17	2.77	2.79	2.82	2.78	2.70
2012 Aug-20 to Aug-24	2.75	2.80	2.80	2.81	2.81
2012 Aug-27 to Aug-31	2.80	2.71	2.64	2.72	2.72
2012 Sep- 3 to Sep- 7		2.81	2.87	2.85	2.73
2012 Sep-10 to Sep-14	2.66	2.82	2.96	3.01	2.94
2012 Sep-17 to Sep-21	2.83	2.74	2.70	2.76	2.76
2012 Sep-24 to Sep-28	2.82	2.84	2.92	3.01	3.08
2012 Oct- 1 to Oct- 5	3.19	3.21	3.21	3.23	3.26
2012 Oct- 8 to Oct-12	3.18	3.18	3.26	3.28	3.38
2012 Oct-15 to Oct-19	3.35	3.27	3.24	3.28	3.43
2012 Oct-22 to Oct-26	3.49	3.34	3.43	3.39	3.38
2012 Oct-29 to Nov- 2	3.40	3.42	3.50	3.50	3.40
2012 Nov- 5 to Nov- 9	3.34	3.41	3.47	3.45	3.33
2012 Nov-12 to Nov-16	3.40	3.57	3.66	3.63	3.46
2012 Nov-19 to Nov-23	3.63	3.62	3.59		3.59
2012 Nov-26 to Nov-30	3.75	3.77	3.71	3.61	3.46
2012 Dec- 3 to Dec- 7	3.44	3.38	3.41	3.48	3.33
2012 Dec-10 to Dec-14	3.35	3.39	3.33	3.27	3.15
2012 Dec-17 to Dec-21	3.20	3.29	3.25	3.35	3.42
2012 Dec-24 to Dec-28	3.30		3.35	3.31	3.40
2012 Dec-31 to Jan- 4	3.43		3.30	3.19	3.20
2013 Jan- 7 to Jan-11	3.30	3.21	3.14	3.08	3.18
2013 Jan-14 to Jan-18	3.39	3.40	3.43	3.44	3.54
2013 Jan-21 to Jan-25		3.63	3.53	3.56	3.42
2013 Jan-28 to Feb- 1	3.25	3.14	3.24	3.33	3.34
2013 Feb- 4 to Feb- 8	3.27	3.34	3.41	3.39	3.26
2013 Feb-11 to Feb-15	3.20	3.30	3.29	3.30	3.19
2013 Feb-18 to Feb-22		3.23	3.34	3.29	3.27
2013 Feb-25 to Mar- 1	3.42	3.46	3.49	3.48	3.54
2013 Mar- 4 to Mar- 8	3.53	3.63	3.57	3.54	3.57
2013 Mar-11 to Mar-15	3.64	3.71	3.72	3.74	3.89
2013 Mar-18 to Mar-22	3.98	3.96	3.97	4.01	4.01
2013 Mar-25 to Mar-29	4.08	3.99	4.08	4.03	
2013 Apr- 1 to Apr- 5	3.97	4.07	4.00	3.94	3.98
2013 Apr- 8 to Apr-12	4.18	4.08	4.07	4.11	4.21
2013 Apr-15 to Apr-19	4.23	4.19	4.24	4.23	4.38
2013 Apr-22 to Apr-26	4.33	4.27	4.25	4.19	4.16
2013 Apr-29 to May- 3	4.28	4.30	4.31	4.28	3.98
2013 May- 6 to May-10	3.93	3.88	3.86	3.87	3.90
2013 May-13 to May-17	3.87	3.93	4.03	4.01	3.89
2013 May-20 to May-24	4.10	4.13	4.16	4.15	4.15
2013 May-27 to May-31		4.19	4.15	4.12	4.02
2013 Jun- 3 to Jun- 7	4.00	4.00	3.99	3.93	3.79
2013 Jun-10 to Jun-14	3.85	3.77	3.74	3.73	3.76
2013 Jun-17 to Jun-21	3.78	3.90	3.93	3.90	3.85
2013 Jun-24 to Jun-28	3.81	3.77	3.72	3.73	3.57

2013 Jul- 1 to Jul- 5	3.52	3.58	3.54		3.52
2013 Jul- 8 to Jul-12	3.65	3.69	3.69	3.64	3.61
2013 Jul-15 to Jul-19	3.67	3.69	3.67	3.66	3.78
2013 Jul-22 to Jul-26	3.71	3.68	3.70	3.68	3.59
2013 Jul-29 to Aug- 2	3.49	3.48	3.46	3.44	3.39
2013 Aug- 5 to Aug- 9	3.33	3.35	3.32	3.27	3.32
2013 Aug-12 to Aug-16	3.34	3.34	3.36	3.34	3.35
2013 Aug-19 to Aug-23	3.46	3.48	3.51	3.52	3.50
2013 Aug-26 to Aug-30	3.55	3.50	3.54	3.58	3.57
2013 Sep- 2 to Sep- 6		3.64	3.68	3.70	3.55
2013 Sep- 9 to Sep-13	3.62	3.65	3.60	3.57	3.60
2013 Sep-16 to Sep-20	3.64	3.77	3.72	3.73	3.68
2013 Sep-23 to Sep-27	3.66	3.59	3.52	3.49	3.51
2013 Sep-30 to Oct- 4	3.48	3.56	3.63	3.58	3.57
2013 Oct- 7 to Oct-11	3.62	3.72	3.70	3.74	3.74
2013 Oct-14 to Oct-18	3.82	3.83	3.84	3.75	3.72
2013 Oct-21 to Oct-25	3.77	3.70	3.66	3.65	3.69
2013 Oct-28 to Nov- 1	3.61	3.57	3.55	3.57	3.45
2013 Nov- 4 to Nov- 8	3.38	3.37	3.46	3.59	3.54
2013 Nov-11 to Nov-15	3.62	3.69	3.69	3.52	3.56
2013 Nov-18 to Nov-22	3.71	3.63	3.63	3.68	3.78
2013 Nov-25 to Nov-29	3.85	3.87	3.87		3.87
2013 Dec- 2 to Dec- 6	3.85	3.84	3.89	3.97	4.15
2013 Dec- 9 to Dec-13	4.24	4.24	4.24	4.40	4.44
2013 Dec-16 to Dec-20	4.21	4.20	4.25	4.25	4.35
2013 Dec-23 to Dec-27	4.52	4.52		4.40	4.34
2013 Dec-30 to Jan- 3	4.41	4.31		4.32	4.39
2014 Jan- 6 to Jan-10	4.50	4.58	4.36	4.15	3.95
2014 Jan-13 to Jan-17	4.19	4.36	4.45	4.55	4.39
2014 Jan-20 to Jan-24		4.61	4.92	5.64	5.17
2014 Jan-27 to Jan-31	5.66	5.25	5.23	5.27	5.04
2014 Feb- 3 to Feb- 7	5.04	5.78	8.12	6.90	5.92
2014 Feb-10 to Feb-14	8.15	7.75	5.96	5.34	5.54
2014 Feb-17 to Feb-21		5.80	6.00	5.96	6.24
2014 Feb-24 to Feb-28	6.08	5.21	4.81	4.61	4.80
2014 Mar- 3 to Mar- 7	7.09	7.98	6.46	4.89	4.78
2014 Mar-10 to Mar-14	4.67	4.67	4.72	4.41	4.40
2014 Mar-17 to Mar-21	4.57	4.42	4.43	4.39	4.33
2014 Mar-24 to Mar-28	4.42	4.53	4.44	4.39	4.50
2014 Mar-31 to Apr- 4	4.48	4.39	4.39	4.51	4.49
2014 Apr- 7 to Apr-11	4.58	4.57	4.67	4.67	4.67
2014 Apr-14 to Apr-18	4.64	4.69	4.64	4.64	
2014 Apr-21 to Apr-25	4.76	4.76	4.81	4.81	4.83
2014 Apr-28 to May- 2	4.72	4.78	4.79	4.79	4.73
2014 May- 5 to May- 9	4.73	4.80	4.82	4.77	4.59
2014 May-12 to May-16	4.52	4.47	4.47	4.42	4.42
2014 May-19 to May-23	4.54	4.53	4.57	4.57	4.40
2014 May-26 to May-30		4.40	4.56	4.63	4.49
2014 Jun- 2 to Jun- 6	4.49	4.62	4.62	4.66	4.66
2014 Jun- 9 to Jun-13	4.67	4.67	4.51	4.51	4.70
2014 Jun-16 to Jun-20	4.71	4.68	4.68	4.67	4.53
2014 Jun-23 to Jun-27	4.53	4.49	4.58	4.58	4.39
2014 Jun-30 to Jul- 4	4.39	4.47	4.47	4.31	
2014 Jul- 7 to Jul-11	4.31	4.18	4.17	4.15	4.13
2014 Jul-14 to Jul-18	4.13	4.13	4.16	4.04	4.08
2014 Jul-21 to Jul-25	3.87	3.81	3.83	3.83	3.86
2014 Jul-28 to Aug- 1	3.84	3.79	3.78	3.78	3.77
2014 Aug- 4 to Aug- 8	3.87	3.87	3.92	3.99	3.94
2014 Aug-11 to Aug-15	4.00	3.94	3.90	3.85	3.80
2014 Aug-18 to Aug-22	3.78	3.84	3.88	3.88	3.88
2014 Aug-25 to Aug-29	3.94	3.99	4.02	4.06	4.04
2014 Sep- 1 to Sep- 5		4.01	3.94	3.91	3.86
2014 Sep- 8 to Sep-12	3.86	3.93	3.98	3.94	3.82
2014 Sep-15 to Sep-19	3.92	3.85	3.97	3.99	3.99

2014 Sep-22 to Sep-26	3.88	3.90	3.84	3.89	3.89
2014 Sep-29 to Oct- 3	3.89	4.14	4.14	4.00	3.94
2014 Oct- 6 to Oct-10	3.89	3.88	3.88	3.87	3.86
2014 Oct-13 to Oct-17	3.87	3.91	3.81	3.80	3.73
2014 Oct-20 to Oct-24	3.69	3.62	3.69	3.60	3.53
2014 Oct-27 to Oct-31	3.56	3.53	3.60	3.76	3.82
2014 Nov- 3 to Nov- 7	3.82	3.67	3.83	3.92	3.92
2014 Nov-10 to Nov-14	4.18	4.18	4.20	4.20	4.05
2014 Nov-17 to Nov-21	4.26	4.33	4.41	4.41	4.32
2014 Nov-24 to Nov-28	4.09	4.09	4.15		4.30
2014 Dec- 1 to Dec- 5	4.30	3.77	3.63	3.63	3.42
2014 Dec- 8 to Dec-12	3.42	3.63	3.65	3.68	3.91
2014 Dec-15 to Dec-19	3.72	3.58	3.72	3.71	3.71
2014 Dec-22 to Dec-26	3.05	2.99	2.99		2.74
2014 Dec-29 to Jan- 2	3.07	3.14	3.14		3.01
2015 Jan- 5 to Jan- 9	3.22	2.98	3.08	2.92	2.96
2015 Jan-12 to Jan-16	2.90	2.92	3.15	3.32	3.11
2015 Jan-19 to Jan-23		2.94	2.94	2.95	2.96
2015 Jan-26 to Jan-30	2.92	2.96	2.89	2.88	2.88
2015 Feb- 2 to Feb- 6	2.88	2.67	2.73	2.66	2.66
2015 Feb- 9 to Feb-13	2.62	2.67	2.86	2.86	2.75
2015 Feb-16 to Feb-20		2.75	2.92	2.92	3.02
2015 Feb-23 to Feb-27	3.22	3.22	3.21	3.21	2.79
2015 Mar- 2 to Mar- 6	2.79	3.00	3.27	3.27	2.89
2015 Mar- 9 to Mar-13	2.75	2.76	2.76	2.82	2.72
2015 Mar-16 to Mar-20	2.68	2.82	2.80	2.86	2.86
2015 Mar-23 to Mar-27	2.72	2.79	2.77	2.77	2.89
2015 Mar-30 to Apr- 3	2.64	2.65	2.62	2.63	
2015 Apr- 6 to Apr-10	2.63	2.71	2.71	2.72	2.58
2015 Apr-13 to Apr-17	2.58	2.58	2.62	2.61	2.67
2015 Apr-20 to Apr-24	2.57	2.59	2.63	2.59	2.59
2015 Apr-27 to May- 1	2.50	2.55	2.55	2.56	2.68
2015 May- 4 to May- 8	2.72	2.76	2.76	2.74	2.78
2015 May-11 to May-15	2.85	2.85	2.85	2.87	2.96
2015 May-18 to May-22	3.01	3.01	3.04	2.96	2.96
2015 May-25 to May-29		2.82	2.82	2.78	2.78
2015 Jun- 1 to Jun- 5	2.78	2.63	2.65	2.60	2.60
2015 Jun- 8 to Jun-12	2.60	2.72	2.81	2.88	2.88
2015 Jun-15 to Jun-19	2.89	2.94	2.93	2.93	2.81
2015 Jun-22 to Jun-26	2.79	2.83	2.83	2.80	2.77
2015 Jun-29 to Jul- 3	2.77	2.80	2.78	2.79	2.79
2015 Jul- 6 to Jul-10	2.79	2.77	2.77	2.70	2.70
2015 Jul-13 to Jul-17	2.88	2.88	2.93	2.90	2.88
2015 Jul-20 to Jul-24	2.88	2.84	2.84	2.92	2.92
2015 Jul-27 to Jul-31	2.92	2.89	2.91	2.87	2.76
2015 Aug- 3 to Aug- 7	2.76	2.83	2.85	2.76	2.76
2015 Aug-10 to Aug-14	2.85	2.84	2.93	2.93	2.83
2015 Aug-17 to Aug-21	2.79	2.71	2.77	2.77	2.70
2015 Aug-24 to Aug-28	2.65	2.71	2.73	2.69	2.69
2015 Aug-31 to Sep- 4	2.70	2.70	2.70	2.67	2.67
2015 Sep- 7 to Sep-11	2.67	2.74	2.74	2.71	2.67
2015 Sep-14 to Sep-18	2.70	2.74	2.69	2.69	2.69
2015 Sep-21 to Sep-25	2.61	2.61	2.62	2.62	2.60
2015 Sep-28 to Oct- 2	2.66	2.57	2.47	2.37	2.37
2015 Oct- 5 to Oct- 9	2.34	2.35	2.35	2.35	2.49
2015 Oct-12 to Oct-16	2.48	2.47	2.47	2.54	2.42
2015 Oct-19 to Oct-23	2.43	2.46	2.37	2.37	2.28
2015 Oct-26 to Oct-30	2.18				

- = No Data Reported; -- = Not Applicable; NA = Not Available; W = Withheld to avoid disclosure of individual company data.

Release Date: 10/28/2015
Next Release Date: 11/4/2015

Referring Pages:

- Natural Gas Futures Prices (NYMEX)

eia U.S. Energy Information Administration

Short-Term Energy and Winter Fuels Outlook

Release Date: October 6, 2015 | **Next Release Date:** November 10, 2015

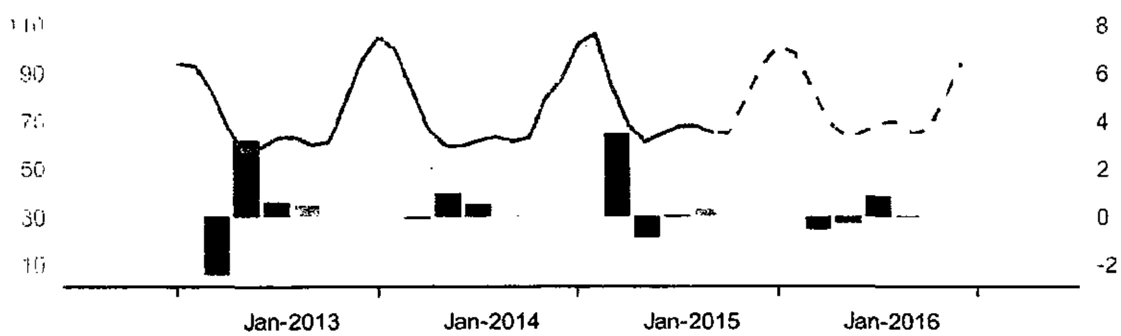
Natural Gas

Natural Gas Consumption

EIA's forecast of U.S. total natural gas consumption averages 76.2 billion cubic feet per day (Bcf/d) in 2015 and 76.4 Bcf/d in 2016, compared with 73.1 Bcf/d in 2014. EIA projects natural gas consumption in the power sector to increase by 15.6% in 2015 and then decrease by 2.1% in 2016. Natural gas prices, which are expected to remain below $3 per million British thermal units (MMBtu) through January 2016, support increased use of natural gas for electricity generation in 2015. Industrial sector consumption remains flat in 2015 and increases by 4.2% in 2016, as new industrial projects, particularly in the fertilizer and chemicals sectors, come online late this year and next year, and as industrial consumers continue to experience low natural gas prices. Natural gas consumption in the residential and commercial sectors is projected to decline in both 2015 and 2016.

U.S. Natural Gas Consumption

DOWNLOAD



— Total consumption (left axis)
- · Consumption forecast (left axis)
Electric power (right axis)
Residential and comm. (right axis)
Industrial (right axis)
Other (right axis)

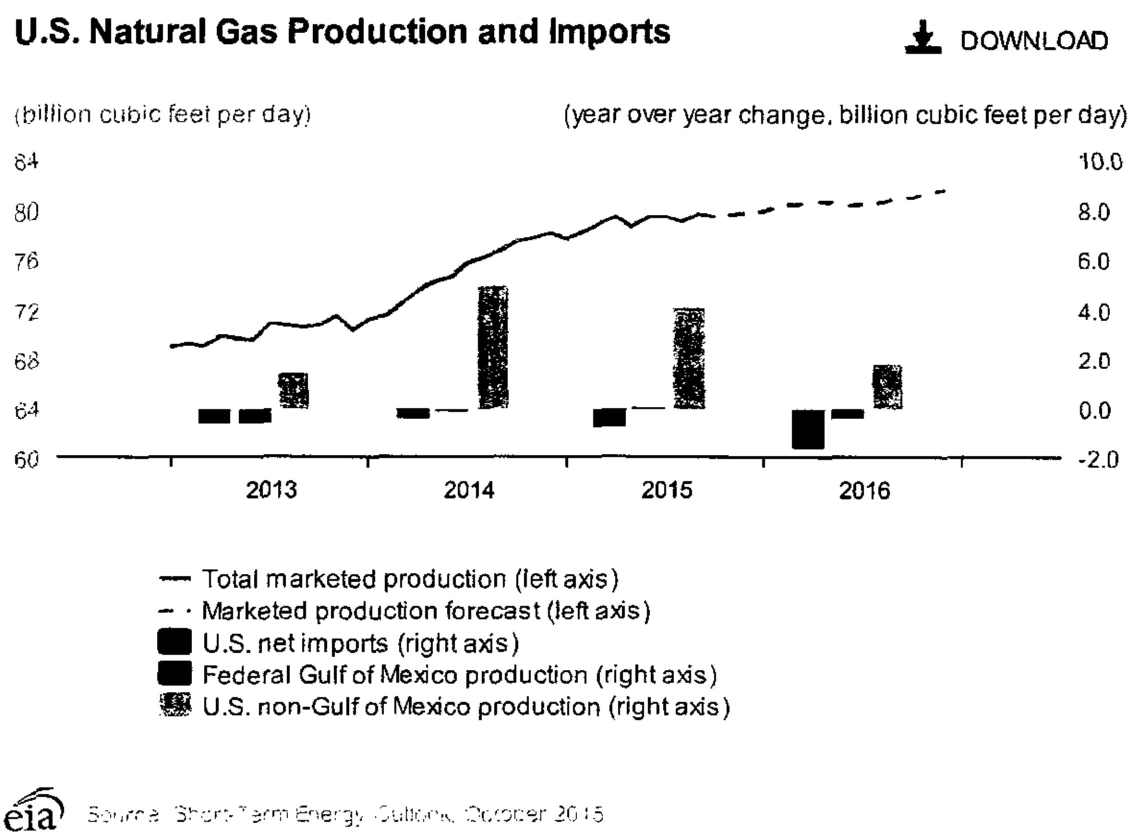
EXHIBIT
SC 86
PENGAD 800-631-6989

eia Source: Short-Term Energy Outlook, October 2015

Natural Gas Production and Trade

EIA expects that marketed natural gas production will increase by 4.2 Bcf/d (5.6%) and by 1.5 Bcf/d (1.9%) in 2015 and 2016, respectively, with increases in the Lower 48 states expected to more than offset continuing production declines in the Gulf of Mexico. Increases in drilling efficiency will continue to support growing natural gas production in the forecast despite relatively low natural gas prices. Most of the growth is expected to come from the Marcellus Shale, as the backlog of uncompleted wells is reduced and as new pipelines come online to deliver Marcellus natural gas to markets in the Northeast.

Increases in domestic natural gas production are expected to reduce demand for natural gas imports from Canada and to support growth in exports to Mexico. Earlier this year, natural gas net imports fell to the lowest monthly level since 1987, averaging 2.3 Bcf/d in both May and June. EIA expects natural gas exports to Mexico, particularly from the Eagle Ford Shale in South Texas, to increase because of growing demand from Mexico's electric power sector coupled with flat natural gas production in Mexico. EIA projects LNG gross exports will increase to an average of 0.79 Bcf/d in 2016, with the startup of a major LNG liquefaction plant in the Lower 48 states at the end of this year.



Natural Gas Inventories

On September 25, natural gas working inventories totaled 3,538 Bcf, 454 Bcf (15%) above the level at the same time in 2014 and 152 Bcf (4%) above the five-year average for that week. EIA projects end-of-October 2015 inventories will total 3,956 Bcf, which would be 158 Bcf above the five-year average, and the highest end-of-October level on record.

U.S. Working Natural Gas in Storage

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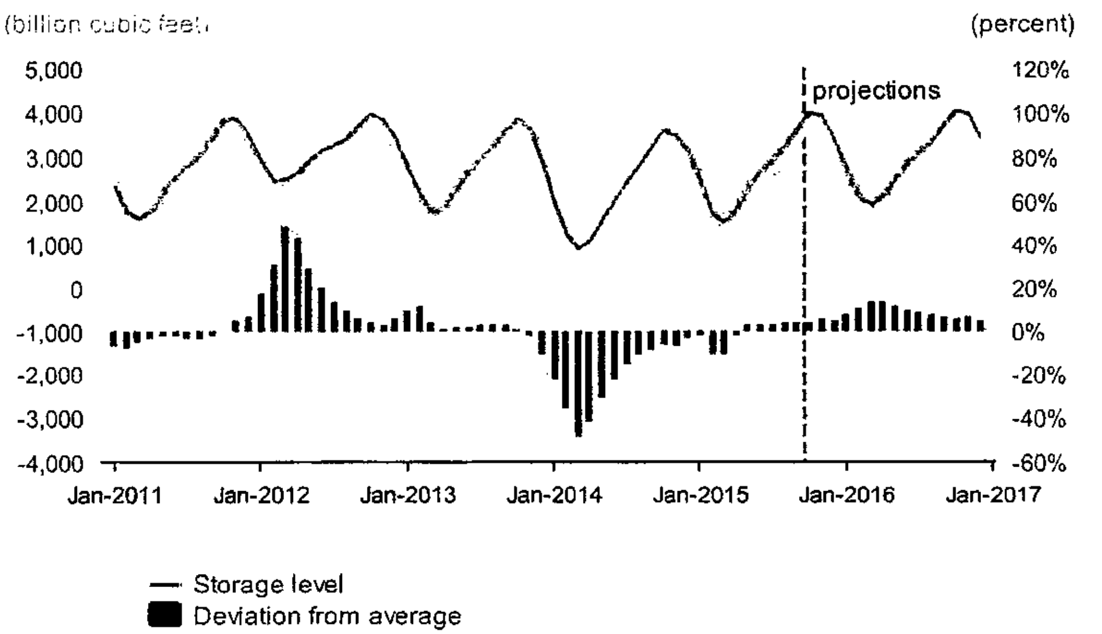


Source: Short-Term Energy Outlook, October 2015

Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014

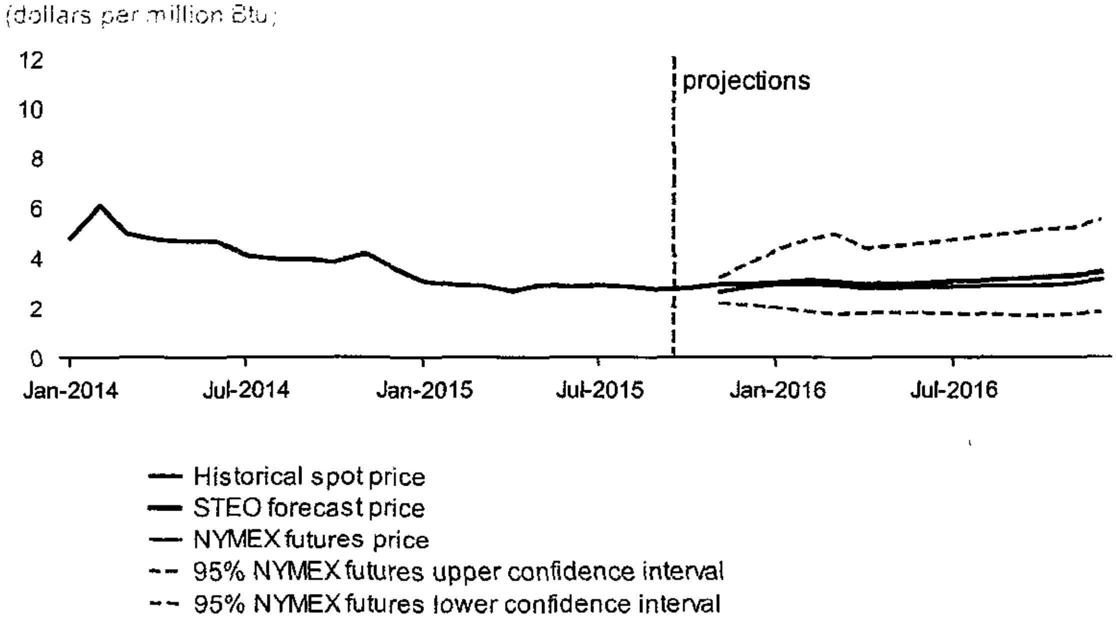
Natural Gas Prices

The Henry Hub natural gas spot price averaged \$2.66/MMBtu in September, a decrease of 11 cents/MMBtu from the August price. Monthly average Henry Hub spot prices are forecast to remain lower than \$3/MMBtu through January, and lower than \$3.50/MMBtu through the rest of the forecast. The projected Henry Hub natural gas price averages \$2.81/MMBtu in 2015 and \$3.05/MMBtu in 2016.

Natural gas futures contracts for January 2016 delivery traded during the five-day period ending October 1 averaged \$2.87/MMBtu. Current options and futures prices imply that market participants place the lower and upper bounds for the 95% confidence interval for January 2016 contracts at \$1.93/MMBtu and \$4.27/MMBtu, respectively. At this time in 2014, the natural gas futures contract for January 2015 delivery averaged \$4.19/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were \$2.96/MMBtu and \$5.94/MMBtu, respectively.

Henry Hub Natural Gas Price

DOWNLOAD

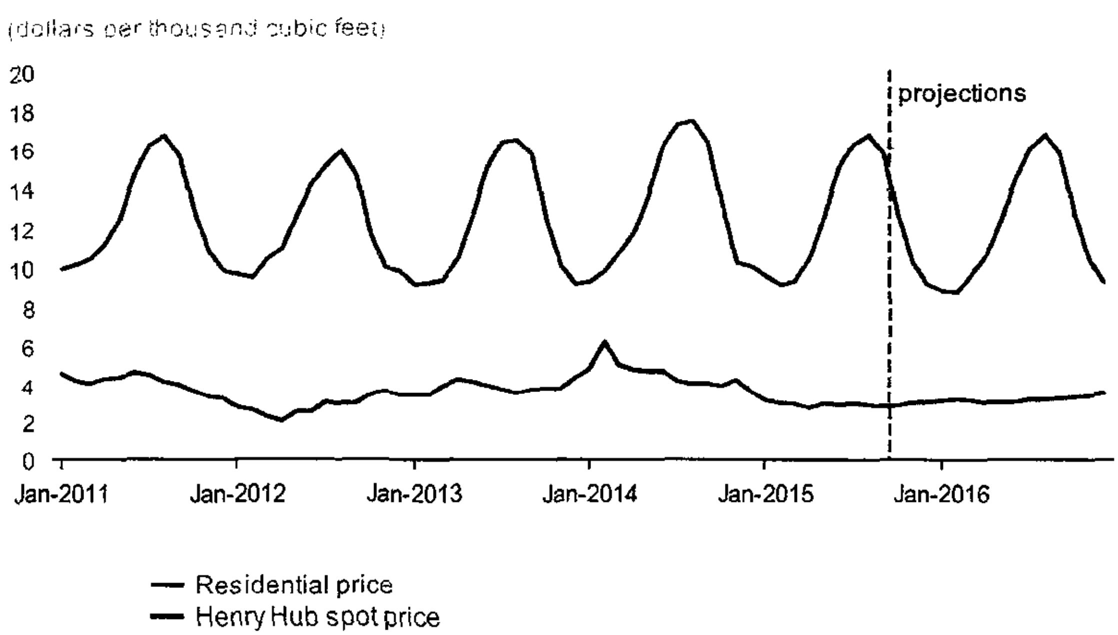


eia Source: Short-Term Energy Outlook, October 2015

Note: Confidence interval derived from options market information for the 5 trading days ending Oct. 1, 2015. Intervals not calculated for months with sparse trading in near-the-money options contracts.

U.S. Natural Gas Prices

DOWNLOAD



eia Source: Short-Term Energy Outlook, October 2015

ICF INTERNATIONAL

WHITE PAPER

New Regime, New Results: Insights from Recent PJM Auctions

By George Katsigiannakis, Himanshu Pande, Rachel Green, and Shanthi Muthiah

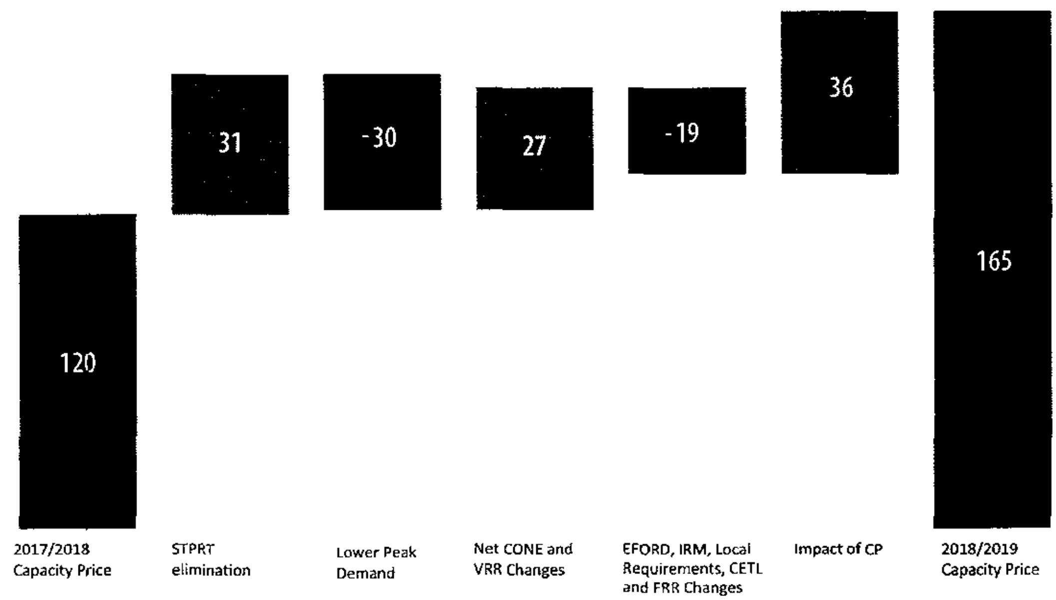
Shareables

1. PJM's restructured Reliability Pricing Model (RPM) has provided higher capacity prices in exchange for greater availability of resources. The increase in prices reflects the risk penalties that generators will face if they underperform, and higher offer caps. Full implementation is not scheduled until the 2020/2021 auction when all purchased resources face Capacity Performance (CP) penalties.
2. The higher capacity prices in the Base Residual Auction (BRA) and transition auctions provide additional revenue for select marginal coal and nuclear resources that did not clear in the prior BRA.
3. Base Product prices in the BRA cleared at only a modest discount to CP Product prices due to lesser overall participation and higher bid levels for resources that did participate.
4. There is one more auction (the 2019/2020 BRA) before all resources are subject to the CP penalties. Given the current proposal to decrease PJM's forecasted peak demand, BRA RTO prices for the 2019/2020 auction could be slightly lower than in the 2018/2019 auction. However, several other market developments, including more aggressive bidding by resources at prices closer to the cap, the Supreme Court ruling on DR participation and forthcoming winter performance and penalty experience, could significantly change this assessment.

What Happened and Why

Historically, changes in structure and auction parameters have been the major source of volatility in the PJM capacity market. Since the implementation of PJM's Reliability Pricing Model (RPM) in 2007, the last auction saw the most dramatic of these changes: (i) a new demand curve was implemented that provides higher capacity prices, especially under excess supply, (ii) the Short Term Procurements Requirements (STRP) rule was removed (a measure that required 2.5 percent of reliability requirements to be set aside and procured in the incremental auctions), (iii) following the triennial schedule, PJM lowered the Cost of New Entry (CONE), (iv) the peak demand for 2018/2019 was revised down, resulting in a decrease of about 3.5 GW in capacity requirements from the last auction (2017/2018 BRA), and (v) implementation of a CP Product (see Table 1 in the Appendix for the key elements of the CP). These are significant changes, especially the CP, most with a major effect on auction results. However, the new demand curve, STPRT elimination, and peak demand revision largely offset one another in the auction, with the implementation of CP effectively increasing the RTO capacity price by approximately \$36/MW-day. In Exhibit 1, ICF provides an estimate of the rough impact of each of these parameters on the PJM RTO capacity price. The \$165/MW-day was the second highest PJM RTO capacity price ever recorded even though the tariff does not schedule full CP implementation until the 2020/2021 BRA to be held in 2017 (procurement in the last auction was 80 percent CP Product), and is the latest in a trend of increasing capacity prices affecting all capacity markets. Prices were even higher in non-RTO markets.

Exhibit 1: Illustrative Offsetting Effects of Implemented Changes in 2018/2019 BRA Auction



NOTE: The graph above reflects the estimated impact of each component assuming a specific sequence. The impact could be different if the sequence is different.

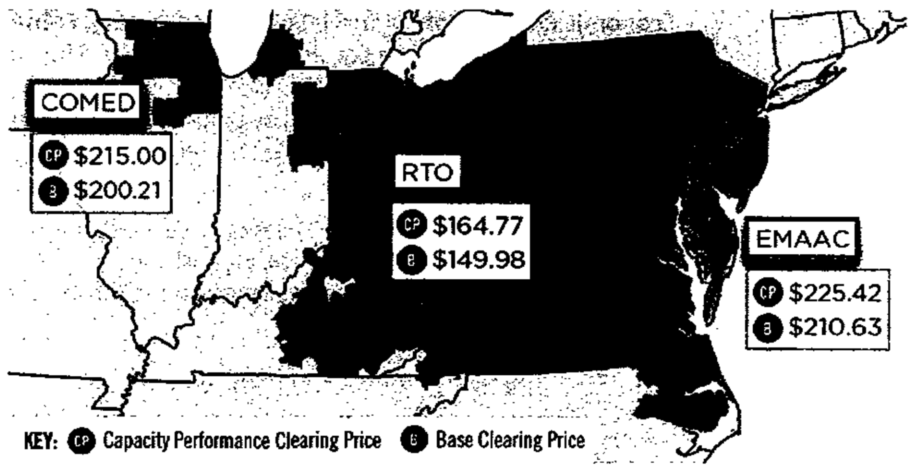
Source: ICF

In addition to the 2018/2019 BRA, PJM also conducted two voluntary transition auctions to procure certain amounts of the highly available CP Product for the 2016/2017 and 2017/2018 capacity periods (periods for which PJM had already procured capacity in the BRA auctions). The RTO capacity prices in the 2016/2017 and 2017/2018 transition auctions cleared at \$134/MW-day (123 percent higher than the BRA price, with only 60 percent CP procurement) and \$152/MW-day (27 percent higher than the BRA price with only 70 percent CP procurement), respectively. MAAC prices in the transition auctions were approximately \$15 to \$32/MW-day higher than the MAAC BRA price in each of those two periods. The premium largely reflects the incremental risk of undertaking the performance obligations for the CP Product relative to the annual Product. The higher price in the 2017/2018 transition auction reflects higher CP requirements, higher offer caps, and higher penalty rates.

Results of the 2018/2019 BRA

CP Product prices cleared within ICF's expectations. RTO cleared at \$164.8/MW-day with separation seen in EMAAC (\$225.4/MW-day) and ComED (\$215/MW-day). Base Product prices saw more convergence with the CP Product prices than expected, with only a \$14.9/MW-day decrement in all regions, except for PPL which saw a \$75/MW-day decrement. Exhibit 2 summarizes the CP and Base Product clearing prices by LDA.

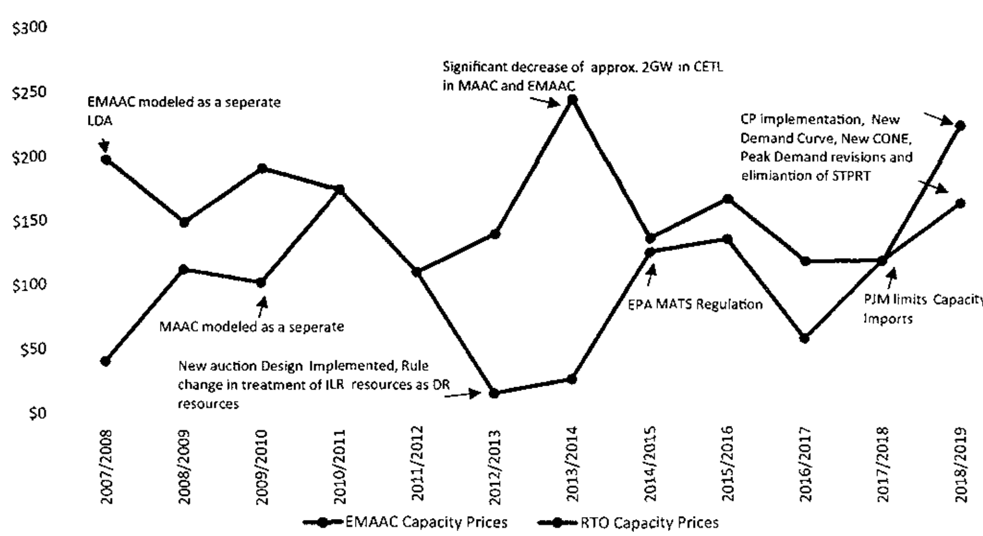
Exhibit 2: 2018/2019 BRA Clearing Prices



Source: PJM

Historically, capacity prices in PJM have been very volatile, averaging \$93/MW-day in RTO and \$159/MW-day in EMAAC in the 2007/2008 to 2017/2018 period (see Exhibit 3) and ranging from a low of \$16/MW-day for RTO to a high of \$174/MW-day for RTO and \$245/MW-day for EMAAC. CP Product prices for the 2018/2019 auction cleared approximately 77 percent higher in RTO and 42 percent higher in EMAAC than the corresponding historical (12-period) average. The RTO capacity price was the second highest ever. Prices were also 38 percent higher in RTO and 88 percent higher in EMAAC for the 2018/2019 auction relative to the previous (2017/2018) auction despite reserve margins at similar levels.

Exhibit 3: Historical RTO and EMAAC Clearing Prices



Source: PJM, ICF

[1] ICF projections for CP Product in the range of \$180 – 200/MW-day were revised downward to the range of \$150 to \$160/MW-day after PJM modified its tariff removing firm fuel requirements for CP Product qualification.

Key Outcomes and Lessons Learned

Economic Bidding Behavior: RTO Aimed at Clearing, EMAAC Closer to Cap: As indicated by the fact that prices cleared at 69 percent of the offer cap in RTO, price increases up to the new, much higher offer cap did not occur for RTO (see Exhibit 4). Even participants with large portfolios who had the power to increase capacity prices by bidding close to the offer cap, did not bid at the offer cap. However, this may reflect a desire to test the legal and political waters before undertaking a more aggressive bidding strategy.

In EMAAC, the story was different. Prices did clear close to the offer cap, indicating in part that (i) units in EMAAC regions have high CP compliance risk (due to a higher number of projected scarcity hours for this region and higher risk from unavailability of fuel) and (ii) limits for capacity imports (CELT) in EMAAC were binding.

The RTO results reflect ICF's competitive price expectations for CP Product bids based on the following formulation:

2018/2019 BRA CP Bid = Going Forward Cost + EFOR CP Risk Premium + Min {Fuel unavailability or environmental limit risk, firm fuel and environmental investment cost}

Where:

Going Forward Cost: ICF estimates of fixed operating and maintenance costs (FO&M) net of estimated 2018/2019 energy margins with gas prices based on NYMEX futures.

EFOR CP Risk Premium: Risk premium associated with the participant's assessment for penalties due to forced outages during Performance Hours.

Fuel Unavailability Or Environmental Limit Risk: Risk premium associated with the participant's assessment of penalties due to lack of fuel or dispatch restriction due to environmental regulations during Performance Hours.

Firm Fuel And Environmental Investment Cost: Annualized investment for firm gas supply or installation of dual fired capability and/or installation of SCR for oil fired units in non-attainment areas.

Before the CP implementation, the applicable offer caps (Avoided Cost Rates) were an important driver of capacity prices. Until now, especially for RTO, bidders' competitive market risk perceptions, rather than the offer caps and their ability to raise prices to cap levels, have been more important. Going forward, participants interested in projecting future clearing prices should monitor and model CP-driven costs (such as Performance Hours and gas pipeline constraints affecting fuel deliveries to power plants) as well as bidding strategy to tease out which effects are truly driving bidding behavior.

Exhibit 4: 2018/2019 BRA Clearing Prices Relative to Offer Caps

	RTO	MAAC	EMAAC	COMED
Offer Cap ($/MW-day)	239	216	227	255
ICAP Net CONE ($/MW-day)	281	254	267	300
CP Resource Clearing Price ($/MW-day)	165	165	225	215
CP Resource Clearing Price as % of Offer Cap	69%	76%	99%	84%
CP Resource Clearing Price as % of Net CONE	59%	65%	85%	72%

Using a stochastic bidding model and the competitive bid formulation provided above, ICF projected the RTO and EMAAC CP Product prices to be in the range of $150-$160/MW-day and $150 to $200/MW-day for EMAAC, indicating that participants likely used a similar methodology in constructing their bids.

Higher prices and a higher range for EMAAC reflects higher risk premiums as the region historically had significantly more Performance Hours (see Exhibit 5) and more gas pipeline constraints (see Exhibit 6).

Exhibit 5: Historical Performance Hours by LDA

Delivery	EMAAC (AE)	RTO
2009/2010	0	0
2010/2011	23	2
2011/2012	22	0
2012/2013	12	7
2013/2014	54	30
Average	**22**	**8**

Source: PJM Independent Market Monitor

Exhibit 6: Number of Effective Operational Flow Orders in PJM

	Jan-14	Jan-15	Feb-14	Feb-15
Transco	4	3	1	2
TCO	0	1	0	0
ANR	0	0	0	0
NGPL	2	1	0	1
TETCO	4	1	0	2
TGP	0	4	0	2
DTI	4	3	0	1
Total	14	13	1	8

Source: PJM 2015 Winter Report

Base Product prices cleared higher than expected: Base Product prices cleared higher than many analysts' expectations, including ICF's. We believe that expectations of low Base Product prices were set before the FERC Order, when PJM's proposal required that a CP resource owner "has obtained and holds, or reasonably expects to obtain and hold, the contractual and other rights necessary to ensure firm fuel supply to each of its affected units during thae Delivery Year." With these strict requirements, market participants expected oversupply and low prices for the Base Product. However, in the July 9th order, when FERC required PJM to relax the requirements for CP qualification, PJM modified its tariff to make it possible for all non-intermittent resources to qualify for CP. This represented a dramatic change in the supply of both Base and CP Product, with more resources qualifying as CP. With expectations for low Base Product prices, few generating resources were offered as Base (i.e. as a Base only resource or in the form of coupled offers) in the LDAs.

Additionally, the offer caps for the Base Product were significantly lower than for the CP Product. As previously mentioned, CP Product offer caps were in the range of $200 to $250/MW-day, while Base Product offer caps were still subject to ACR-based offer caps. ACR-based offer caps varied by resource type and were as low as $30/MW-day for CC and CT units, ranging up to $170/MW-day for coal units. These offer caps were further reduced by the estimated energy margins for these resources. Resources that had the option to submit coupled offers for CP and Base Product largely decided to offer as CP only if the Base Product offer cap was too low and not reflective of the relatively small risk discount of Base Product compared to CP Product. For example, a gas-fired generator with a cost-based CP bid of $160/MW-day would want to offer as a Base Product at approximately $150/MW-day (reflecting the risk discount for only facing penalties in summer months). Thus, being over the Base offer cap, they would choose to bid as CP only, reducing the supply of Base Product. Furthermore, the bid levels for the resources that did bid as Base Products had high bid price levels.

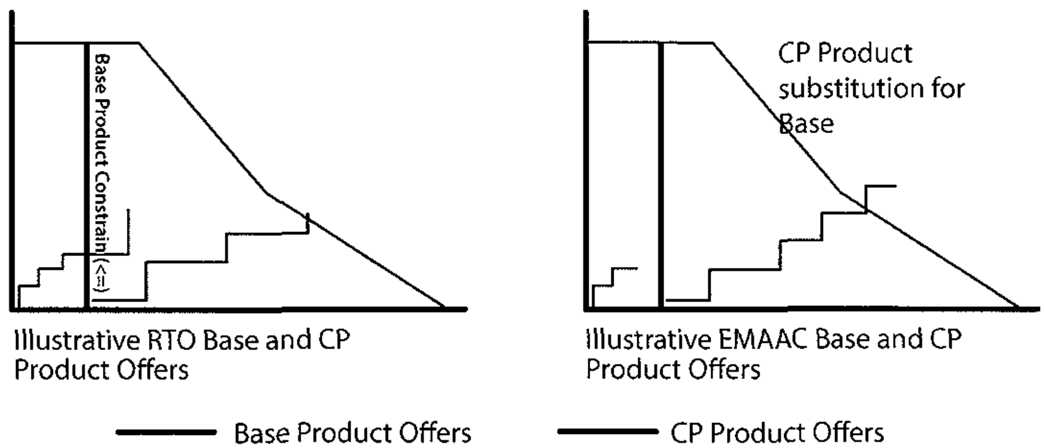
Base Product prices saw separation from the CP Product prices because there was some excess Base capacity in RTO. The relatively high Base Product requirements specified by PJM in the EMAAC and COMED LDAs (compared to the relatively low RTO Base Product constraint, see Exhibit 7) combined with relatively low participation for the Base Product (either in the form of coupled or Base-only offers) to result in Base Product capacity shortages in all the LDAs. Only RTO had excess Base Product capacity, resulting in the small price separation between Base and CP Product (see Exhibit 8). The PJM algorithm dictates that if the Base Product constraint is binding in the RTO region and non-binding in the LDAs, then the RTO price decrement is applicable to all non-binding LDA regions (to derive the Base Product pricing in the other regions).

Exhibit 7: Base and CP Requirements by LDA for 2018/2019

% of Total Requirements	Base Requirement[1]	CP Requirements
PJM Region	16%	84%
MAAC	24%	76%
EMAAC	35%	65%
PS NORTH	28%	72%
COMED	40%	60%

Source: PJM, ICF

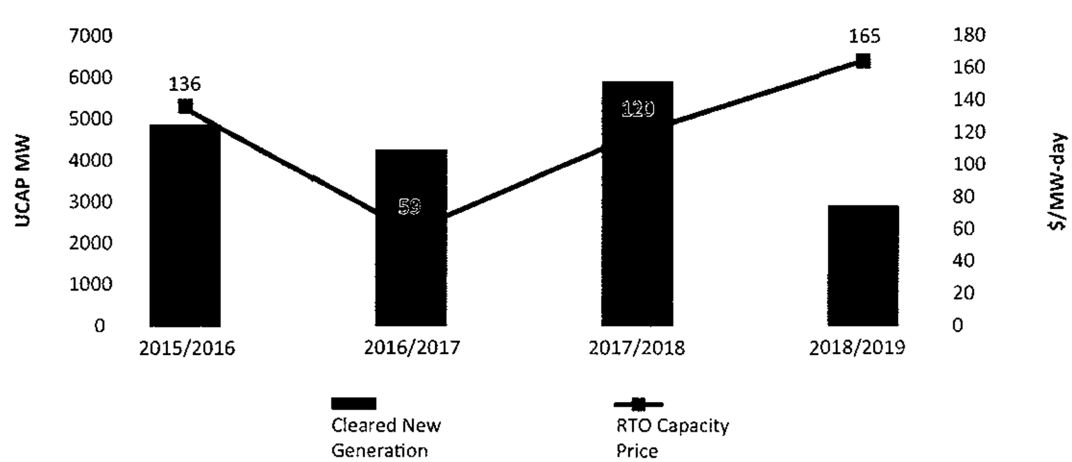
Exhibit 8: Illustrative RTO and EMAAC Base and CP Offers



Source: PJM

Relatively small amount of new generation: Fewer new capacity resources (3 GW) cleared in the 2018/2019 BRA than in recent previous auctions, even though the clearing prices were higher (exhibit 9). This is likely due to the risk of higher penalties if a plant does not come online by the beginning of the capacity period[2] and to some degree, due to the increased credit requirements for new resources. As illustrated in Exhibit 10, historically, a large amount of capacity that cleared in the previous auctions was delayed coming online. In addition, the 3-month delay of the auction may have magnified developers' concerns about not being able to have the new power plants online by June 1, 2018.

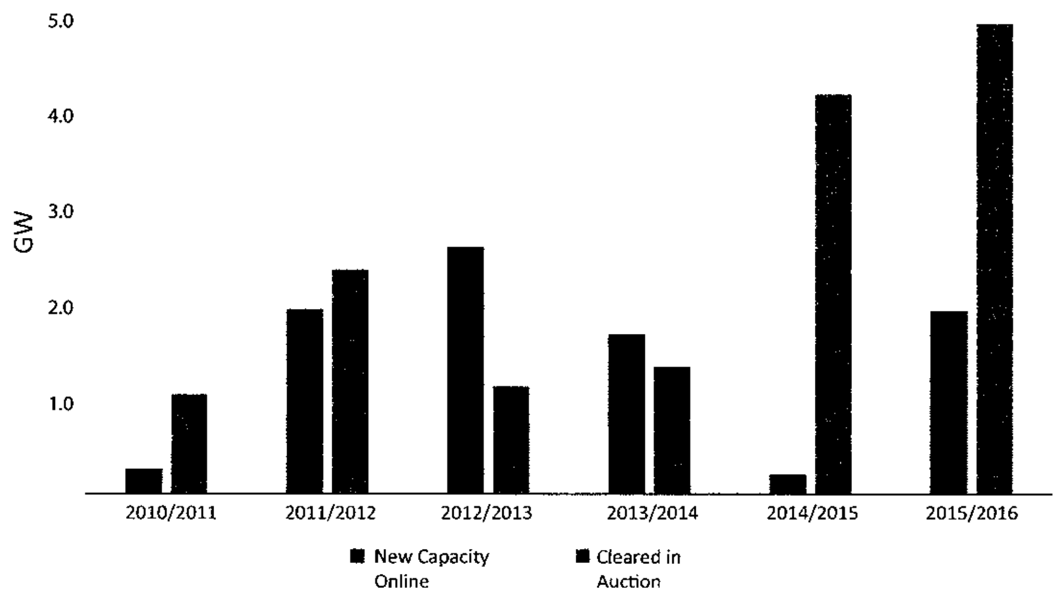
Exhibit 9: BRA New Generation and RTO Clearing Prices



Source: PJM, ICF

[2] FERC rejected PJM's initial proposal to exempt planned generation resources from capacity must-offer requirements until they become operational.

Exhibit 10: Capacity Additions in PJM



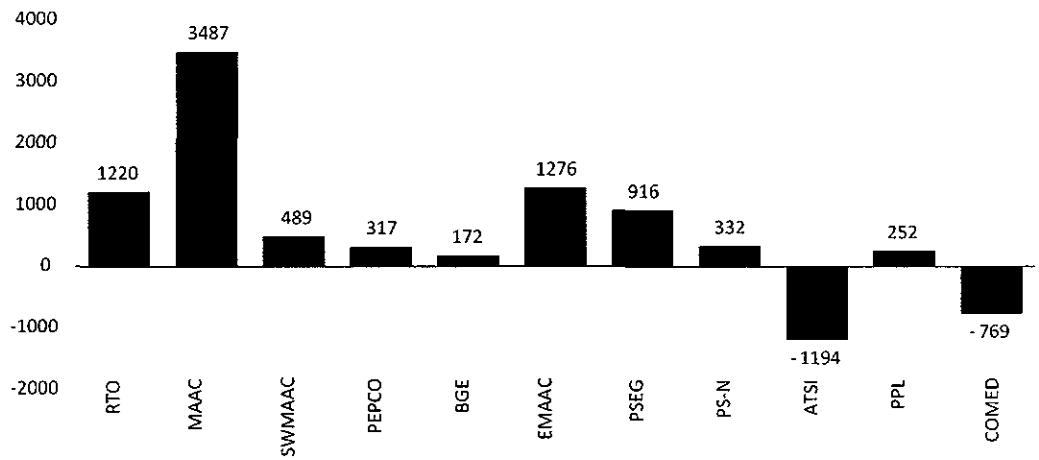
Source: PJM, SNL Financial, ICF

With the implementation of CP, the incentives for speculative bidding for new resources have been reduced. This will be even more significant in the 2019/2020 auction when new units will be required to execute a Facility Study Agreement before being permitted to offer into the BRA. In short, PJM seems to have achieved the goal of designing incentives so that bidding resources are actually likely to become operational, and therefore that capacity clearing in the market will be present and on schedule. Regardless of the relatively small participation of new capacity resources in the last auction and the concerns that the new market structure will make it harder to finance new generating resources, ICF believes that a significant portion of the 13 GW that requested MOPR exceptions will bid and most likely clear in the next few auctions. New units continue to appear to have favorable economics as indicated by the fact that 85 percent of the new capacity offered cleared the auction.

PSEG announced that the 527 MW that cleared in the EMAAC region reflects its Sewaren 7 project in Woodbridge, New Jersey. ICF believes that the remaining 2.5 GW of new capacity in RTO includes the Moundsville project in APS, Advance Power's Carroll County in AEP, and the Middletown and Meigs County projects in the Duke Energy and AEP regions.

Change in un-cleared capacity location: The last auction saw a net increase of 1.2 GW in un-cleared capacity across PJM over the 2017/2018 capacity period, (13 GW vs 11.8 GW) (see Exhibit 11). Uncleared capacity increased in the gas dominated regions of eastern PJM and decreased in western PJM. The un-cleared capacity in MAAC and EMAAC increased by 3.5 GW and 1.3 GW respectively. ICF believes this is primarily due to higher expected scarcity hours and going forward costs in eastern regions of PJM, resulting in higher bids.

Exhibit 11: Change in un-cleared capacity between 2017/2018 and 2018/2019 Auction



Source: PJM, ICF

The decrease in uncleared capacity in ATSI indicates that First Energy likely cleared Mansfield 1-3, units that did not clear in previous auctions. Similarly, the decrease in uncleared capacity in COMED, as announced by Exelon, reflects the fact that the Byron nuclear unit cleared the auction. Exelon announced that the Three Mile Island nuclear unit, which cleared the 2017/2018 auction, did not clear, which explains the increase in uncleared capacity in MAAC.

Weak price signals from MISO market: The slight 3 percent increase in imports (by 160 MW to 4,688 MW) from the 2017/2018 BRA indicates that market participants do not expect the MISO capacity market to provide the price signals needed to maintain merchant MISO capacity, even though MISO is expected to face capacity shortages by the 2018/2019 capacity period. PJM reports that all imports were exempt from the Capacity Import Limits (CIL's) i.e. external resources committed to PJM for the 2018/2019 capacity period will have firm transmission into the PJM and will qualify for CP Product.

To evaluate changes to PJM imports in upcoming auctions, stakeholders should closely monitor developments in MISO capacity markets. In addition, because of high Base Product pricing, stakeholders should also account for the potential of more imports without firm transmission that could be offered as Base Product in the 2019/2020 capacity period.

DR/EE participation slightly up: To ICF's and other market analysts' surprise, the level of Demand Response (DR) and Energy Efficiency (EE) clearing in the market increased slightly compared to 2017/2018. This marginal increase was primarily due to the elimination of the DR factor,[3] resulting in an increase in the UCAP of DR resources. It was largely expected—as occurred in ISO-NE with the implementation of their Pay-for-Performance Initiative (PI)—that the amount of DR participation would decline. Approximately 11 GW cleared in total, largely as Base Product (9.6 GW). Of this amount, slightly more than half bid as Base only, 1 GW bid as CP only, and 4 GW submitted coupled offers. Most units that submitted coupled offers cleared as Base; the fact that the clearing prices of Base and CP were very close indicates that these units must have had high CP bids. Going forward, the capacity that submitted coupled offers will likely continue to offer as CP Product. By 2020, when the CP Product requirements will increase, these units clearing as CP would push up the prices.

The importance of the Supreme Court's decision on the legality of DR and EE participation in capacity markets needs to be seen in the context of upward price pressure due to full implementation of CP even if the court does not act. This decision could affect the volume of DR, especially if state by state

[3] The DR Factor was used to further derate the ICAP capacity of DR Resources.

replacement of DR incentives are not smooth. It could also affect prices to some degree, especially if advocates of DR would otherwise be able to reinstate differential and preferential treatment for DR in the absence of the decision.

Transition Auction Results

In addition to the 2018/2019 BRA, PJM also conducted two voluntary transition auctions to procure certain amounts of the highly available CP Product for the 2016/2017 and 2017/2018 capacity periods (periods for which PJM has already procured capacity in the BRA auctions), i.e. 60 percent and 70 percent of reliability requirements, respectively. Another key differentiator for the transition auctions, in addition to even lower procurement of CP Product than the recent BRA, is that there is no consideration of local requirements, which results in a single clearing price across the entire RTO.

The RTO capacity prices in the 2016/2017 and 2017/2018 transition auctions cleared at $134/MW-day (123 percent higher than the BRA price, with only 60 percent CP procurement) and $152/MW-day (27 percent higher than the BRA price, with only 70 percent CP procurement), respectively. MAAC prices in the transition auctions were approximately $15 to $32/MW-day higher than the MAAC BRA price in each of those two periods. ICF believes units' bids in the transition auctions reflected, at minimum, their corresponding BRA price in order to ensure that they would earn at least what they had already realized in the respective BRA. Units added to this Base price an additional risk premium based on their expected performance during scarcity hours to account for the additional risk incurred by participating in the CP market.

Transition Auction Bid = Corresponding BRA Price + Forced Outage Risk Premium + Min (Fuel Unavailability or environmental limit risk, Firm fuel and environmental investment cost)

2016/2017 Transition Auction: The price differential between the Rest-of-RTO and MAAC 2016/2017 BRA prices largely influenced the clearing price of the 2016/2017 transition auction. In the 2016/2017 BRA, the majority of capacity cleared at either the rest-of-RTO or MAAC price, $59.37/MW-day or $119.13/MW-day respectively. In the 2016/2017 BRA, As the rest-of-RTO capacity price was lower than the MAAC price, units in the rest-of RTO had significantly more scope to increase their bids and still clear the auction (approximately $60/MW-day). ICF estimates that approximately 57 GW was available in rest of RTO with little additional cost, and approximately 27 GW was available with increased costs to address higher risk of fuel unavailability or environmental limitations. Thus, it was possible that the 2016/2017 CP requirement of approximately 95 GW could have been largely met by units in rest of RTO. However, ICF believes that the most expensive units in the rest-of-RTO had bids above the lower cost units in MAAC, thus resulting in approximately 79 GW of cleared capacity in RTO and 16 GW of cleared capacity in MAAC, with MAAC units setting the price for all units at $134/MW-day (approximately $14/MW-day higher than the corresponding BRA price). Approximately 4.2 GW of supply without commitment in the 2016/2017 BRA cleared in the auction, reflecting 3.5 GW of previously uncleared coal capacity and 0.6 GW of DR and EE. Most of the previously uncommitted capacity (2.5 out of 4.2 GW) was from the ATSI territory, indicating that First Energy most likely cleared the Mansfield power plant.

2017/2018 Transition Auction: Prices in the 2017/2018 auction cleared $18/kW-yr higher than in the prior transition auction, largely due to the higher CP requirement of 17 GW (to approximately 112 GW) and the higher penalty rate by approximately $500/MWh (to $2420/MWh) Since there was no price difference in the 2017/2018 BRA price of RTO and MAAC (both cleared at $120/MW-day), the rest of RTO units did not have the price advantage in this transition auction. This development, coupled with the higher CP requirement, resulted in more capacity clearing from MAAC in the 2017/2018 transition auction than in the 2016/2017 auction. In total, approximately 74 GW of capacity cleared in the rest of RTO and 38 GW of capacity cleared in MAAC at a capacity price of $152/MW-day.

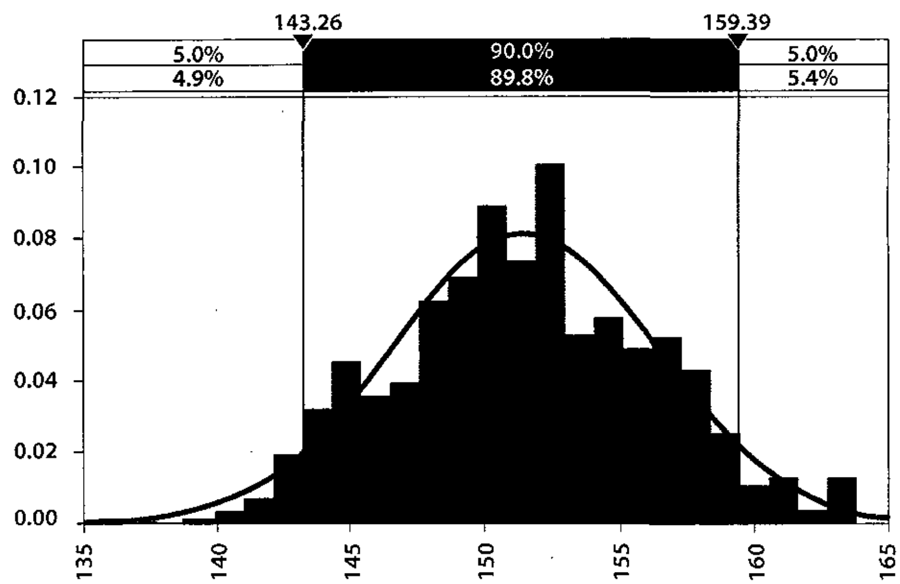
PSEG units, whose BRA price was \$215/MW-day, likely did not participate in the 2017/2018 transition auction because the offer cap was set at \$210.83/MW-day. The PSEG units that had previously cleared were better off with their \$215/MW-day BRA prices, while the units which did not previously clear *were unlikely to clear in the transition auction due to higher capacity price requirements.*

The amount of cleared capacity without previous commitments increased from 4.7 GW in the 2016/2017 transition auction to 9.3 GW, reflecting 4.1 GW of coal units and 4.3 GW of nuclear. Exelon announced that all its nuclear plants that did not clear the 2017/2018 BRA, including Byron, Quad Cities, and Oyster Creek, cleared in the transition auction. With this development, Exelon indicates that it plans to keep all its nuclear fleet online up to June 2018 and decide on the future of its Illinois fleet (and participation in the 2019/2020 BRA) based on the ongoing Illinois legislative proposals (H.B. 3328, H.B. 2607, and H.B. 3293).

Looking Ahead

There is one more auction scheduled with less than 100 percent procurement of CP Product. ICF believes there is plausible scenario in which there could be a slight decline in the RTO capacity price for the 2019/2020 BRA, notably in a scenario with lower peak demand projections. Using ICF's stochastic PJM BRA bidding model, there is a 90 percent confidence interval of approximately \$143 to \$159/MW-day for the RTO CP Product (see Exhibit 12) in a scenario in which (i) the lower peak demand forecast of approximately 4 GW proposed by the PJM Load Sub-Committee in September 2015 is implemented in the upcoming auction (this remains highly uncertain), (ii) some new generation capacity clears, (iii) energy margins reflect recent natural gas futures and basis differentials for the 2019/2020 period, (iv) CETL limits remain constant, (v) the Exelon nuclear fleet continues to bid their net going forward cost, (vi) there is no change in the participation of DR (in reality, the Supreme Court on the EPSA ruling could have a major impact on DR participation), and (vii) there is no increase in the willingness of entities to bid closer to the offer caps in the RTO (in reality, willingness could be affected by their perception of legal and political risks).

Exhibit 12: Illustrative 2019/2020 BRA RTO Clearing Price



Source: ICF

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In addition to the factors listed above, forthcoming experience in the winter of 2015/2016 and the number of Performance Hours could also modify the risk assessments of market participants, resulting in different bids and capacity prices.

APPENDIX

TABLE 1 – KEY ELEMENTS OF THE CP PROPOSAL

- **Compliance Hours** are defined as the hours during which PJM declares emergency actions. CP Resources will be evaluated for their performance during these hours and will be assessed performance payments (bonus or penalties) at a predefined $/MWh Performance Payment Rate (PPR) based on any deviations of the resource's actual performance from its Expected Performance.
- **Expected Performance (EP)** of a CP resource reflects its pro-rata share of system requirements during compliance hours. The performance payments for a CP resource dispatching at MWactual during compliance hours are calculated using the following formulas:

  Performance Payments ($) = (MWactual – EP) * PPR

  EP (MW) = MWcleared * (Peak Demand + Reserve Requirements) / (MW committed from all resources)

  Where:

  PPR ($/MWh) = (Net CONE/30 hours) * 365 days
- **Balancing Ratio (BR)** is the ratio [Peak Demand + Reserve Requirements] / [MW committed from all resources] and is a measure of the performance of the system during compliance hours.
- **Offer Caps:** existing units that qualify as CP Product can be offered in the auctions at a price up to Net CONE times the corresponding Balancing Ratio. This is a significant increase from the existing offer caps that reflect going forward costs (net ACR).
- **Transition Auctions:** to create a glide path for a smooth transition to the new system, there will be transition auctions for the 2016/2017, 2017/2018 and 2018/2019—2019/2020 periods where the CP Product will be procured at 60 percent, 70 percent and 80 percent of PJM's reliability requirements respectively, with corresponding decreases on penalty rates and offer caps.

  For a detailed discussion of the CP proposal visit: icfi.com/insights/white-papers/2015/capacity-performance-changing-pjm-iso

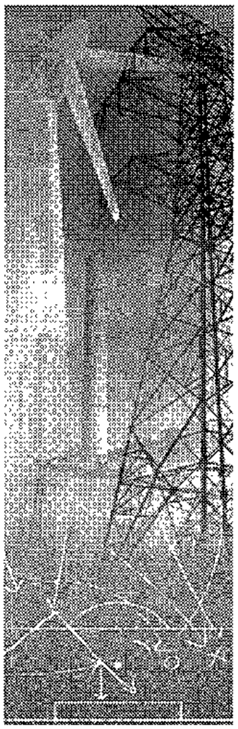
For questions, please contact:

George Katsigiannakis | george.katsigiannakis@icfi.com | +1.703.934.3223
Shanthi Muthiah | shanthi.muthiah@icfi.com | +1.703.934.3881

WHITE PAPER

Capacity Performance: Changing the Game in PJM ISO

By George Katsigiannakis, Shanthi Muthiah, Rachel Green, and Himanshu Pande, ICF International



The Bottom Line

1. PJM Interconnection LLC's (PJM's) proposed new capacity market mechanisms to better value performance and penalize underperformance will push PJM regional transmission organization's (RTO's) capacity prices up to $170 to $200/MW-day for RTO and even higher for some constrained locational deliverability areas (LDAs). Energy prices will be slightly lower in the long term. Low-compliance-cost oil, coal, and nuclear units will be first in line to bid and benefit from these higher prices.
2. We find that the existing fleet can satisfy PJM RTO's new requirements, but only if significant investments are made.
3. Stakeholders must consider their new bidding strategy and adjusted investment plans carefully. New sell-side mitigation rules will result in a dramatic change in the bidding behavior and the dynamics of the auction. Previously, avoided cost recovery (ACR) offer caps drove the bids of existing generation and planned generators trying to outbid existing generators. Now with offer caps up to net cost of new entry (Net CONE), both planned and existing generators will compete on an equal basis to provide the capacity performance (CP) product requirement. Fierce competition will likely drive RTO CP product prices significantly below Net CONE.

Abstract

The severe winter weather during the 2013–2014 "Polar Vortex" pushed the system in PJM closer to the brink than many thought was possible and led to historic price spikes in energy markets. This event shed light on the surprising weakness in the reliability of generation resources and potential flaws in the capacity market mechanisms meant to value both capacity and performance under constrained conditions.[1]

In response, PJM has proposed phasing in a new capacity market design that compensates owners for reliability investments and penalizes underperformance. We find that the existing fleet can satisfy PJM RTO's new CP requirements, but only if significant investments are made, especially by gas units lacking dual-fired capacity which may need investments in the range of $30/MW-day to $60/MW-day to comply. Based on our assumed cost for firm fuel supply and projected risk premiums, we anticipate that the price of the CP product in the upcoming auction will be in the range of $170 to $200/MW-day for RTO and significantly higher (at Net CONE levels) for some constrained MidAtlantic Area Council regions. We also project some concurrent decreases in energy prices.

These broad findings, combined with other implications of the PJM proposal described in this paper, would have significant consequences for market stakeholders. Low-compliance-cost oil, coal, and nuclear units will bid and clear first in the new capacity market, benefitting from higher prices. Gas-fired units without firm supply will in turn need to make significant and costly investments to meet PJM's new requirements. All generators will have to adjust their capacity market bids to factor in a risk premium for underperformance penalties.

[1]See Rose, Judah, "Waiting for the Next Polar Vortex," Public Utilities Fortnightly, June 2014.

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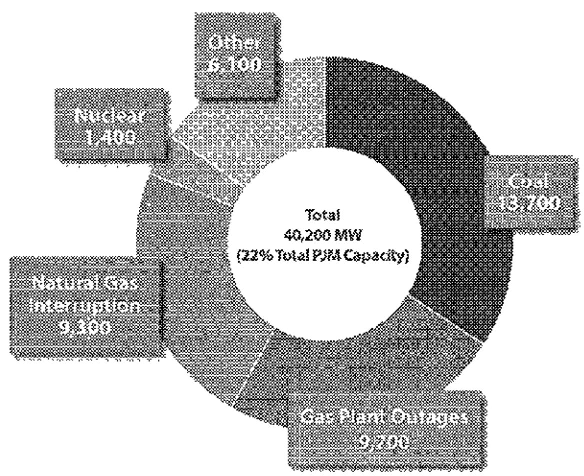
Demand response (DR) resources will face a new regime limiting which resources can participate in capacity markets. And there will be added incentives to locate new planned units closer to (relatively less expensive) fuel supply. ICF continues to work on more detailed analysis for clients to help guide investment choices, asset and reliability-based investment valuation, and market bidding strategies.

The Capacity Underperformance Problem

In January 2014, the Polar Vortex led to two periods of extreme cold from January 6 to 12 and January 17 to 29, during which PJM experienced forced outage rates three times higher than expected. Although mechanical issues caused by extreme cold contributed to many of the forced outages, a substantial portion was due to problems in securing either primary or secondary fuel (see Exhibit 1).

Exhibit 1: Sources of January 7 Evening Peak (7 p.m.) Forced Outage



Source: PJM ISO "Problem Statement on PJM Capacity Performance"

This underperformance of capacity during the Polar Vortex demonstrated that the capacity market had not properly incentivized reliability and firm fuel supply under severe operating conditions. Generation owners find the cost of investments in reliability (e.g., securing a firm gas contract, dual-fire capability, and increased maintenance) to be more expensive than the penalties that could be incurred for underperformance during outage events. The problem is exacerbated even further by several factors:

- The PJM capacity market excuses any outages due to fuel-supply interruptions from penalties.
- Generation owners are not allowed to include the cost of firm fuel supply in supply offers and therefore cannot recover this cost.
- A self-reinforcing effect occurs: Generation owners fear that any incremental reliability-based investment will make them less competitive if other market participants are not making these investments.

All of these issues discourage investments in reliability, and the result is higher-than-expected forced outages rates during stress conditions. Exhibit 2 shows the negative correlation between capacity prices and forced outage rates beginning in the 2011–2012 auction year.

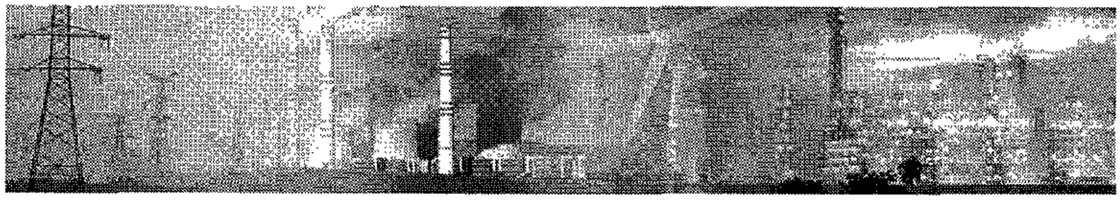
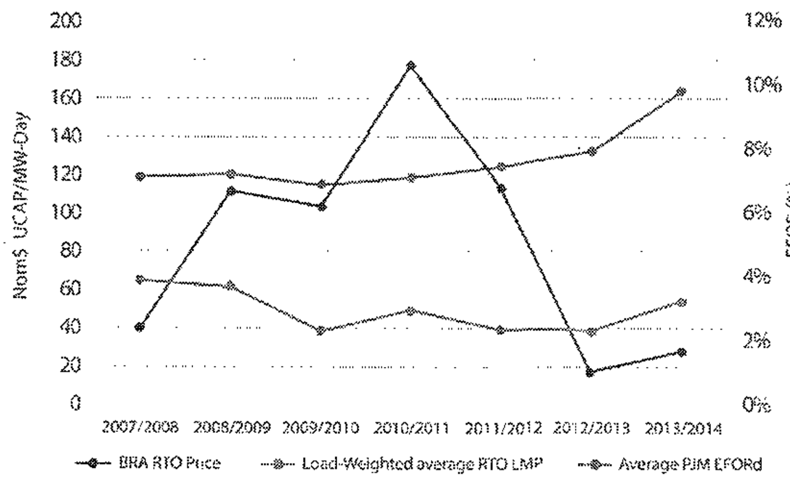


Exhibit 2: Historical PJM Average Forced Outages and Capacity Prices



Source: PJM ISO "Capacity Performance Action Items"

Improving capacity market incentives will be particularly important in the future as more coal plants retire and the market relies even more on gas-fired units—renewables that are either less flexible or require firm fuel supply to be reliable.

In response during the past year, PJM ISO proposed and FERC approved a number of initial changes meant to improve system reliability and optimize participation of DR and energy efficiency resources.[4] Further individual reform proposal were ultimately shelved, however, in favor of pursuing a more comprehensive and far-reaching restructuring proposal, the CP product.

Capacity Performance Proposal

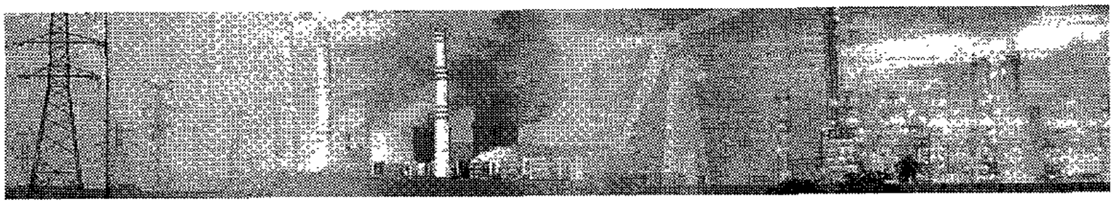
The most consequential change for capacity in PJM is a major restructuring of the reliability pricing model (RPM) itself with PJM ISO's new CP product proposed to the Federal Energy Regulatory Commission (FERC) on December 12, 2014 (ER15-623-000). Based on ISO-NE's Pay-for-Performance Initiative, the CP product would create a two-settlement process where capacity revenue now comprises a base payment plus penalties for underperformance or credits for overperformance during compliance hours (the hours when PJM declares an emergency action (i.e., voltage reduction, or manual load dump warnings or actions).[5]

How Payments Are Determined

Penalties or credits would be calculated using performance payments rates (PPRs, expressed in $/MWh) that reflect the applicable Net CONE (expressed in $/MW-day) normalized over the compliance hours. The relevant rate would then be applied to the resource's actual performance, compared with its expected performance in order to calculate the total penalty or bonus.

[4] These include a) an upper limit of 4 percent of the reliability requirement for limited DR programs and an upper bound of 10 percent for the aggregate amount of limited and extended summer DR, b) stricter registration requirements for demand side management (DSM) resources to ensure that DR resources are valid, and c) capacity import limits on the amount of external generation capacity that can be reliably committed to PJM, both for each of five external source-zones and for the overall RTO.

[5] Under this definition in the last 2013–2014 capacity period, PJM experienced 23 compliance hours. Because it projects more scarcity in the future, PJM ISO proposes to assume a rate of 30 compliance hours for upcoming capacity periods, although it can file to change this assumption at any point.



Expected performance of a CP resource reflects its pro-rata share of the system requirements during compliance hours.

How Penalties and Bonuses are Calculated

For each hour during and emergency action, the performance payment for each resource is calculated based on the following formulas:

Performance Payments ($) = (MWactual – EP) * PPR

EP = MWcleared * (Peak Demand + Reserve Requirements)/(MW committed from all resources)

PPR = (Net CONE/30 hours) * 365 days

EP—Expected Performance

PPR—Performance Payment Rate

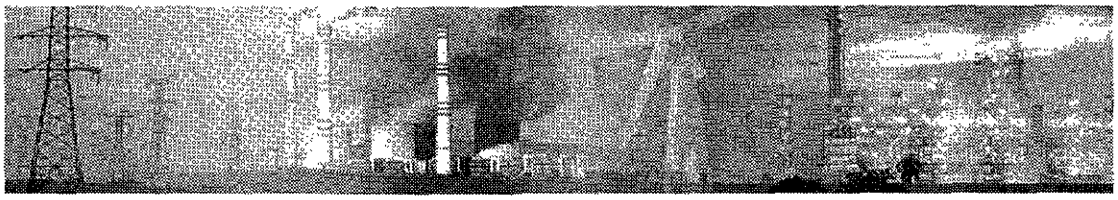
However, PJM proposed putting boundaries on the amount of penalty or credit in order to limit risk—annual and monthly stop loss provisions that (after a transition period) would be set at 1.5*Net CONE and 0.5*Net CONE, respectively.

Further Reliability Incentives

To fix some of the lack of incentives for firm supply in the current capacity mechanism, starting with the 2018–2019 base residual auction (BRA), offer caps for CP resources would be set at Net CONE (although PJM would allow higher values to be approved under ACR review), and the existing ACR methodology also would be adjusted to include the cost of firm fuel supply (adjusted duel availability expense [AFAE]) and the risk premium of CP resources (capacity performance quantifiable risk [CPQR]). The phase-in structure for several reliability incentive mechanisms during the transitional auctions is outlined in Exhibit 3.

Exhibit 3: Transitional Capacity Auction Characteristics

	CP Product				Base Capacity Product
	% of Reliability Requirement	**Offer Caps**	**Performance Payment Rates**	**Annual Stop Loss**	**% of Reliability Requirement**
2016–2017	60% - procured on voluntary basis in special auction in April 2015	50% of Net CONE	50% of (Net CONE/30)*365	0.75*Net CONE	40%
2017–2018	70% - procured on voluntary basis in special auction in May 2015	60% of Net CONE	60% of (Net CONE/30)*365	0.9*Net CONE	30%
2018–2019 and 2019–2020	80% - In BRA auctions with must offer obligations	Net CONE or higher	(Net CONE/30)*365	1.5*Net CONE	20%
2020–2021+	100% - In BRA auctions with must offer obligations	Net CONE or higher	(Net CONE/30)*365	1.5*Net CONE	20%



Timeline for Implementation and Who Will Qualify

To allow time for resources to improve their reliability along a glide path rather than in a sudden transition, PJM plans to phase in CP during the next five auction periods. In the interim, PJM would maintain an enhanced version of the existing annual capacity product, called the base capacity product. Base capacity resources would only be assessed penalties for underperformance during summer months. Which plants would be CP compliant is not clear, because the proposed PJM rule does not provide hard criteria (only 14 hours start up and 1-hour notification requirements). However, PJM has stated that fossil generators cleared as annual product and expected to be available during the 700 hours of high-peak demand would qualify for CP product. Harsh penalties for misrepresenting qualifications should steer participation.

Demand Response Resources in the CP Proposal

A great deal of attention has been paid to how DR will be treated in future capacity auctions, given the recent legal uncertainties. PJM's CP proposal attempts to maintain the status quo by treating DR programs as resources; however, it plans to eliminate limited DR from all upcoming auctions. It also allows extended summer DR to participate as a base product in the transition auctions subject to a limit of 8.3 percent of peak demand for the RTO. After 2020–2021, however, only annual DR can participate as a CP product. PJM also filed with FERC an alternative treatment for DR resources. In this filing, if the U.S. Supreme Court upholds the District Court Electric Power Supply Association decision, PJM ISO proposed to include DR resources on the demand side, allowing (only) load-serving entities to use DR resources to decrease their RPM requirements.

Implications of the CP Product: Winners, Losers, and New Investment

We project that PJM's proposal will have significant impacts across the market, including slightly higher Base Capacity prices and much higher capacity prices in the CP product as well as a longer term dip in energy prices. Higher capacity prices will be driven by the fact that not enough low-compliance-cost resources are available to meet PJM's CP requirements. Coal and nuclear units could have a relatively low-compliance cost by making boiler modifications and weatherization investments. Oil units also could offer CP products with relatively little investment, as long as their generation is not restricted by environmental or other ordinances. These types of units will be the first in line to offer and clear the market. But ICF estimates that after accounting for these compliant- and low-compliance-cost units, in the upcoming BRA auction, the PJM RTO still will be short of its CP requirements by approximately 10 GW. Therefore, gas units—many of which would require significant investments to become compliant—also would need to offer CP products.

Those that can already dual fire (or that are planned relatively close to—and can therefore less expensively access—firm gas supply) will have a more manageable compliance cost. However, those without dual-firing capability would have to procure firm gas supply (commodity and firm transportation contracts) or install dual-firing capabilities. For some power plants, firm contracts may not be available, and the only option to qualify as a CP product would be dual firing. The costs of these investments vary widely and can be anywhere from $30/MW-day to $60/MW-day or more, depending on location and technology type. Resources would add these investment costs to their bids in the BRA auction, driving up capacity prices. In the longer term, these costs also would affect investment behavior in other ways, as portfolio owners factor in the costs of firm fuel supply into planned locations of new units.

In addition to the investment costs, bids now also would include the risk of performance penalties, further elevating capacity prices. The expected risk premium can be estimated using the NET Cone and resources' historical forced outage rate. For example, a combined cycle (CC) unit with a historical

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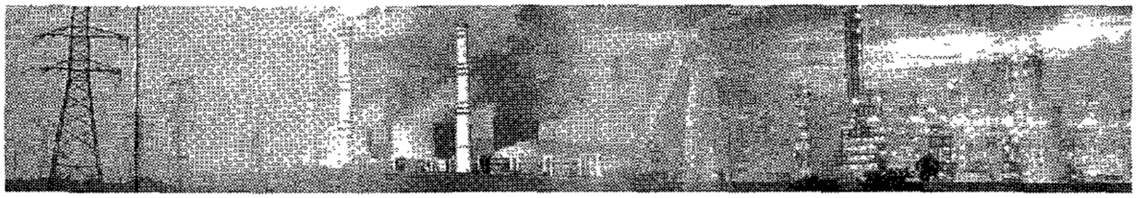

forced outage rate of 3.6 percent and a NET Cone of $300/MW-day would increase its bid by $11/MW-day or $4/kW-year. Risk premiums for participation as a base-capacity resource are expected to be lower than those for CP participation because they have a shorter time frame in which to face penalties. A resource would not participate in either auction if the expected cost of nonperformance is higher than its annual capacity revenue, so the risk premiums should be considered as a price floor. With the use of the above costs, ICF simulations indicate CP product prices in the range of $170 to $200/MW-day for RTO and significantly higher (closer Net CONE levels) in the constrained Eastern Mid-Atlantic Area Council (EMAAC) regions.

At equilibrium, the price of the base-capacity product PBR and the price of the CP product PCP can be linked with the following formula:

PCP = PBR + Cost of secure fuel + CP Performance Risk Premiums

Although based on the fundamentals, the price of the base-capacity product should be around $130/MW-day. Depending on the participation of DR resources, the prices of base capacity could be significantly lower. These estimates include the effect of the new demand curve and new CONE values that have been proposed by PJM and filed with FERC as well as the elimination of the short-term procurement target (i.e., 2.5 percent hold-back of reliability requirements for BRA auctions for procurement in incremental auctions).

Although the CP product increases capacity prices, it would lead to lower energy prices for these reasons: (1) more supply from new efficient units (ICF's simulations indicate approximately 5 GW of more new capacity expansion in 2018–2019 period, compared with the capacity expansion without CP implementation) (2) lower energy market bids during peak conditions (CP resources are required to offer their capacity as economic in the day-ahead energy market), and (3) improved performance from existing units (to avoid performance penalties, existing resources would have greater availability and lower forced outage rates, and thereby increase the supply of energy. With a greater supply, all else equal, energy prices would be on average lower).

Conclusions and Next Steps

PJM's proposal would fundamentally alter the incentives and strategies for capacity and energy market participants and their related stakeholders. Individual businesses will need to carefully assess their approach to firm supply and incremental builds. ICF has the expertise and the right modeling tools to help market participants understand and benefit from these dramatic changes in PJM markets. ICF assists market participants in making investment decisions to optimize their position for the new market, assessing the value of reliability investments, formulating bidding strategies, and valuing current or prospective resources in the new market constructs. We help stakeholders to better understand and hedge against risk, and to prepare for future developments as the market continues to evolve and adjust.

For questions, please contact:

George Katsigiannakis | +1.703.934.3223 | gkatsig@icfi.com
Shanthi Muthiah | +1.703.934.3881 | shanthi.muthiah@icfi.com

ICF INTERNATIONAL

Judah Rose Direct Testimony

Before the Public Utilities Board of Manitoba Hydro
February 22, 2011

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Averaging forecasts has the following advantages:

- Different forecasts draw on varying information and emphasize different issues – averaging captures these diverse views and evens out extreme positions
- They may use different methods of forecasting – averaging likely to offset errors

Professors Larrick and Armstrong recommend this approach to forecasting (excerpts from WSJ article on next page)

In fact, MH prices are even higher than the consensus forecasts (i.e., the average of forecasts from five independent consultants). MH's approach to use consensus forecasts plus a premium as a minimum for pricing long-term contracts is reasonable. This helps guard against seller's regret, i.e., regret if spot prices turn out to be higher, and ensures Manitoba Hydro negotiators have access to up-to-date information.

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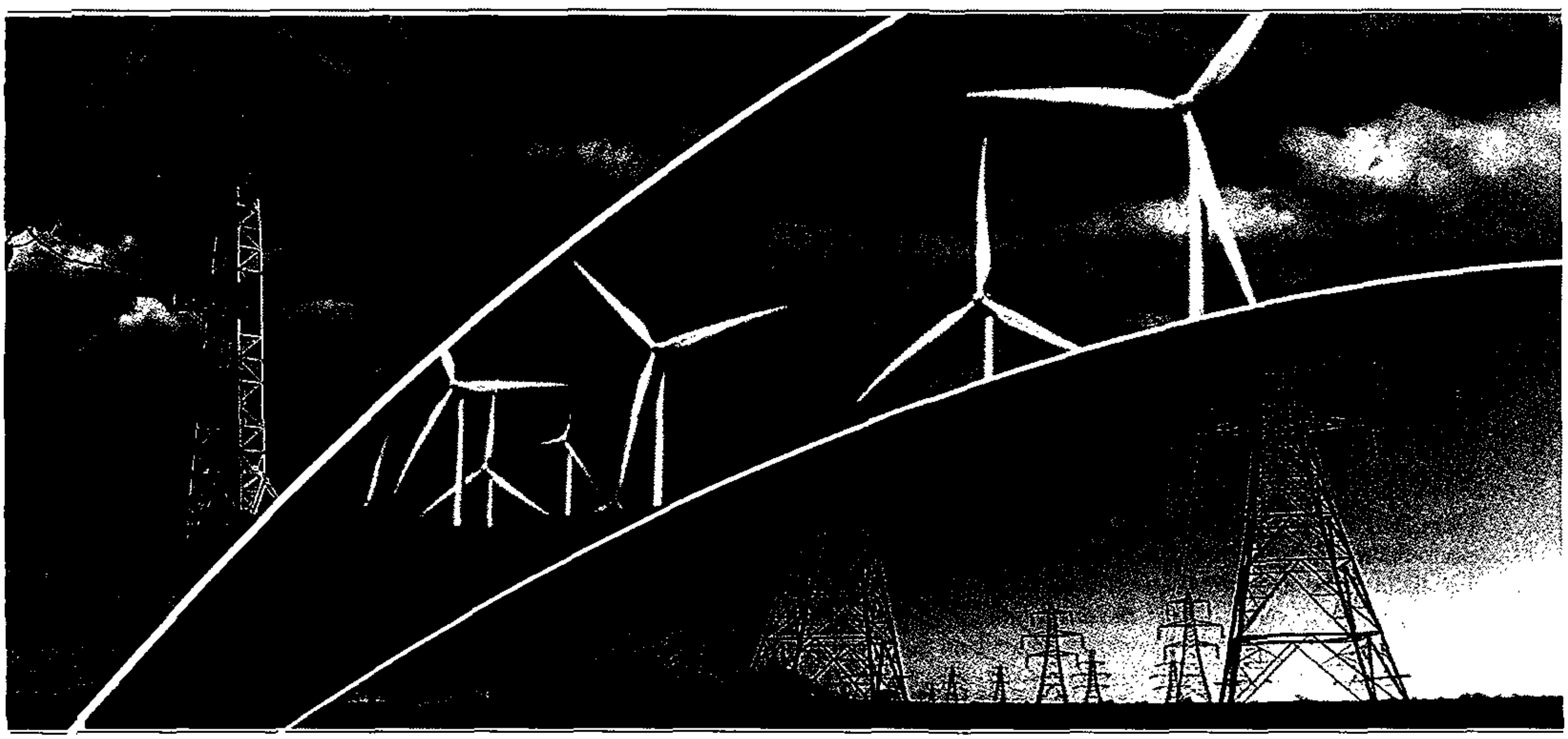
"Perhaps the most powerful tool for improving the quality of predictions is simply to combine several forecasts from a variety of independent sources...Forecasts from different sources tend to draw on varying information and divergent methods, so their errors will frequently offset one another."

Professor Armstrong "has found that [the] technique [of averaging forecasts] reduces forecasting errors by up to 58% - a massive improvement over individual forecasts."

Source: "Making Sense of Market Forecasts," Wall Street Journal, January 8, 2011

DOE/EIA-0383(2014) | April 2014

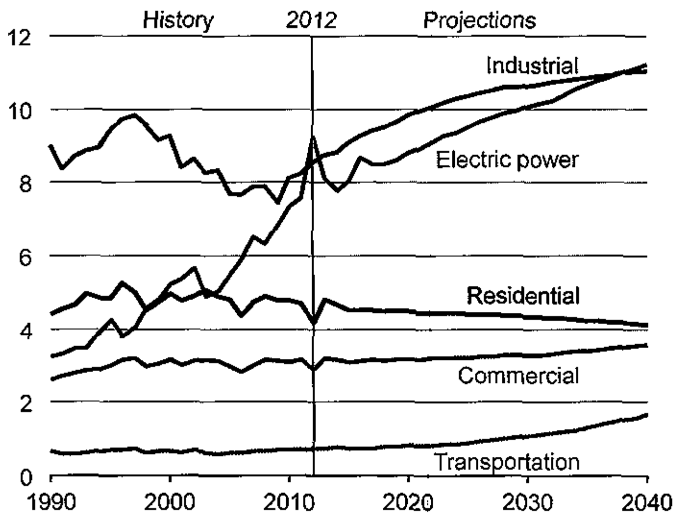
Annual Energy Outlook 2014
with projections to 2040



Independent Statistics & Analysis
U.S. Energy Information Administration

Industrial and electric power sectors drive growth in U.S. natural gas consumption

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040 (trillion cubic feet)



U.S. total natural gas consumption grows from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040 in the AEO2014 Reference case. Natural gas use increases in all of the end-use sectors except residential (Figure MT-39). Natural gas use for residential space heating declines as a result of population shifts to warmer regions of the country and improvements in appliance efficiency.

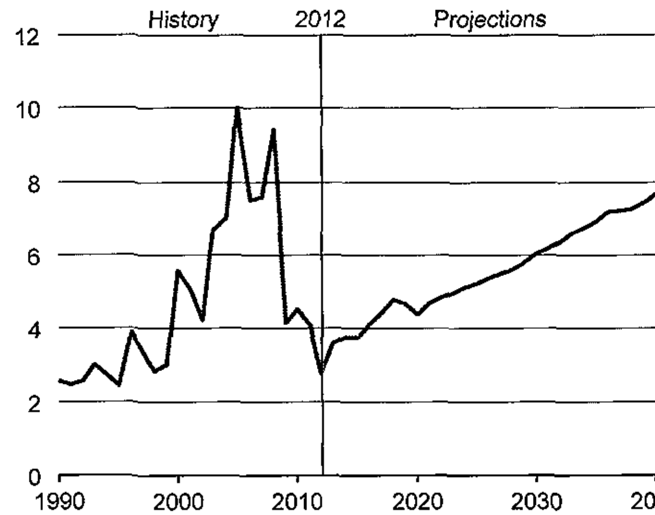
Consumption of natural gas for electric power generation grows by about 2 Tcf and makes up about 33% of the increase in total natural gas consumption by 2040. Relatively low natural gas prices make natural gas an attractive fuel for serving increased load. Natural gas is also the fuel most often used to replace older coal-fired generation as it is retired.

From 2012 to 2040, natural gas consumption in the industrial sector increases by 2.5 Tcf, an average of 0.9%/year, representing about 26% of the total increase in natural gas consumption. As industrial output grows, the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2028. After 2028, industrial sector consumption of natural gas continues to grow but at a somewhat slower rate, in response to rising prices.

Although transportation use currently accounts for only a small *portion of total U.S. natural gas consumption, natural gas use by* heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection. Consumption in the transportation sector, excluding natural gas use at compressor stations, grows from about 40 billion cubic feet (Bcf) in 2012 to 850 Bcf in 2040.

Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)



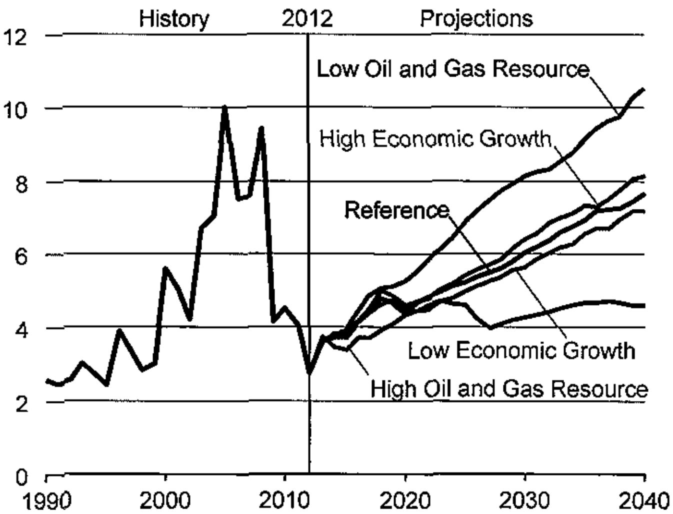
Average annual U.S. natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies. To provide the supplies necessary to meet growth in natural gas consumption and a rise in exports in the AEO2014 Reference case, producers move into areas where the recovery of natural gas is more difficult and expensive, which leads to an increase in Henry Hub spot prices over the projection period. Henry Hub spot prices for natural gas increase by an average of 3.7%/year in the Reference case, from $2.75/million Btu (MMBtu) in 2012 to $7.65/MMBtu (2012 dollars) in 2040 (Figure MT-40).

Growth in demand for natural gas, largely from the electric *power and industrial sectors and for liquefied natural gas* (LNG) exports, results in upward pressure on prices, particularly in the 2015-18 period. Delivered prices to residential, commercial, industrial, and electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in *areas that do not serve the Henry Hub is somewhat faster than* growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. Total onshore production in the Northeast region grows on average by 3.2%/year, from 3.3 Tcf in 2012 to 8.1 Tcf in 2040, while combined onshore and offshore production in the Gulf region grows by 2.1%/year, from 7.3 Tcf in 2012 to 13.0 Tcf in 2040.

Natural gas prices

Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



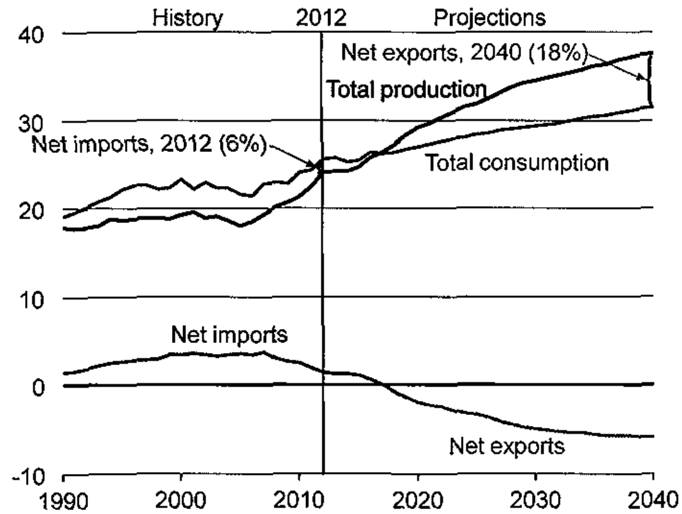
The projection of natural gas prices depends on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas, primarily in response to their effects on housing starts, commercial floorspace, and industrial output. In the High Economic Growth case, higher levels of consumption result in more rapid increases both in depletion of natural gas resources and in the cost of developing new production, pushing natural gas prices higher. The converse is true in the Low Economic Growth case (Figure MT-41). In the High and Low Economic Growth cases, the price rises by 4.0%/year and 3.5%/year, respectively, compared with 3.7%/year in the Reference case.

The rate of resource recovery from oil and natural gas wells has a direct impact on the cost per unit of production and, in turn, prices. The High Oil and Gas Resource case assumes higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska than in the Reference case. The Low Oil and Gas Resource case assumes lower estimated ultimate recovery of natural gas from each shale well or tight well than in the Reference case. In the Low and High Oil and Gas Resource cases, Henry Hub spot natural gas prices increase by 4.9%/year and 1.8%/year, respectively. (An article in the Issues in focus section, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," provides more information on the alternative resource cases.)

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to increases in natural gas exports and demand, which place some upward pressure on natural gas prices.

With production growing faster than use, the U.S. becomes a net exporter of natural gas

Figure MT-42. Total natural gas production, consumption, and imports in the Reference case, 1990-2040 (trillion cubic feet)



In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.

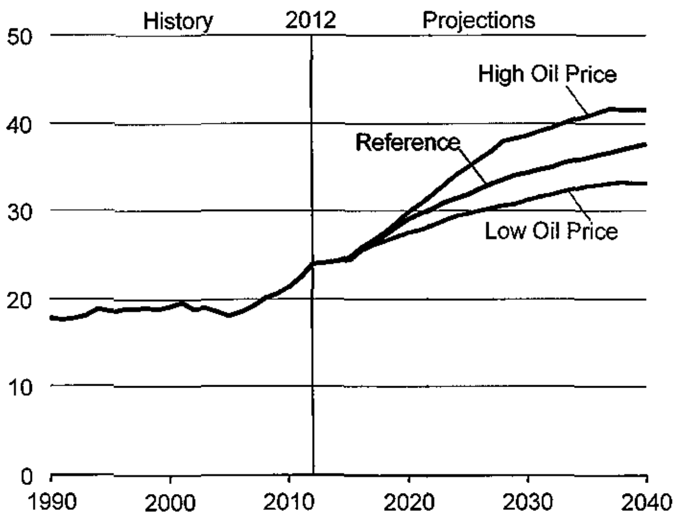
The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors. Growing LNG exports also support higher natural gas prices.

The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).

Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico. Net pipeline imports from Canada drop from 2.0 Tcf in 2012 to 0.4 Tcf in 2030, mainly as a result of lower imports to the western United States. Imports from Canada increase to 0.7 Tcf in 2040, with higher imports into the northeastern United States. In contrast, net pipeline exports to Mexico grow steadily, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040.

U.S. natural gas production, use, and exports all are affected by oil prices

Figure MT-43. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



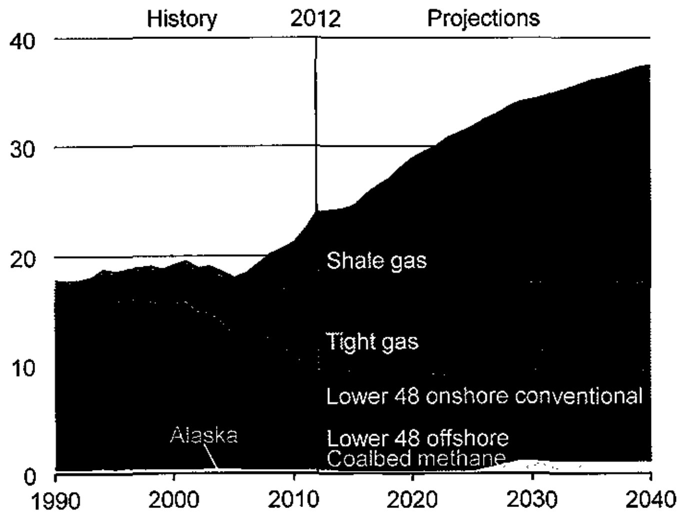
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the oil price cases, the largest changes in consumption are seen for natural gas consumed in transportation and natural gas exported as LNG.

The profitability of natural gas as a transportation fuel or as LNG for export depends primarily on the price differential between crude oil and natural gas. For example, in the Low Oil Price case, the average difference between oil prices and natural gas prices from 2012 through 2040 is about $7.70 per million Btu (MMBtu). With that low price differential, virtually no natural gas is consumed in the transportation sector, and little LNG is exported. In the High Oil Price case, in contrast, the average price difference is about $21.90/MMBtu, which provides substantial incentive for direct use of natural gas in transportation and for conversion to LNG for export.

Across the oil price cases, total natural gas production varies by 8.3 Tcf in 2040 (Figure MT-43), with changes in LNG exports accounting for 6.3 Tcf and changes in direct consumption for transportation accounting for 2.2 Tcf. The increase in LNG exports and transportation consumption is offset to some extent by lower natural gas consumption in other sectors, with spot prices for natural gas from 2012 to 2040 averaging about $0.70/MMBtu higher in the High Oil Price case than in the Low Oil Price case.

Shale gas provides the largest source of growth in U.S. natural gas supply

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)



The 56% increase in total natural gas production from 2012 to 2040 in the AEO2014 Reference Case results from increased development of shale gas, tight gas, and offshore natural gas resources (Figure MT-44). Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production increases from 40% in 2012 to 53% in 2040. Tight gas production and offshore gas production increase by 73% and 78%, respectively, from 2012 to 2040, but their shares of total production remain relatively constant.

From 2017 to 2022, U.S. offshore natural gas production declines by 0.3 Tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 Tcf in 2040, as natural gas prices rise.

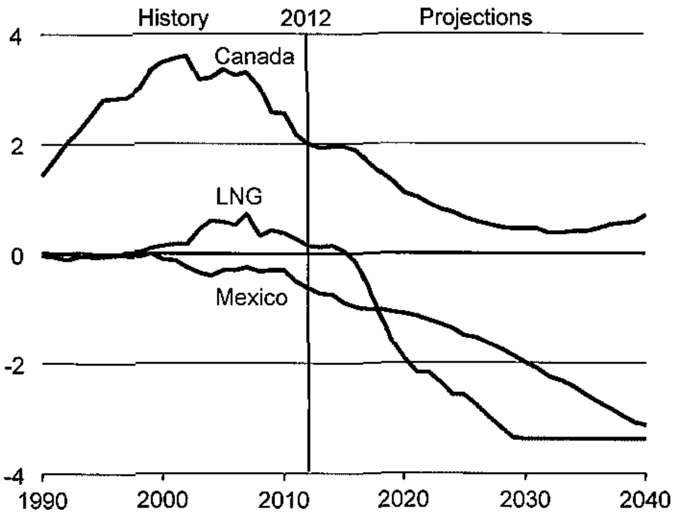
Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 Tcf (2.2 Bcf/d) in 2029. Alaska's LNG exports level off at 0.8 Tcf per year over the last decade of the projec-tion. Alaska's total natural gas production in 2040 is 1.2 Tcf.

Although U.S. natural gas production rises throughout the projection, the mix of sources changes over time. Onshore non-associated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 Tcf in 2012 to 1.6 Tcf in 2040, and in 2040 it accounts for only about 4% of total domestic production, down from 16% in 2012.

Natural gas trade

U.S. exports to North American and overseas gas markets increase as gas production rises

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040 (trillion cubic feet)



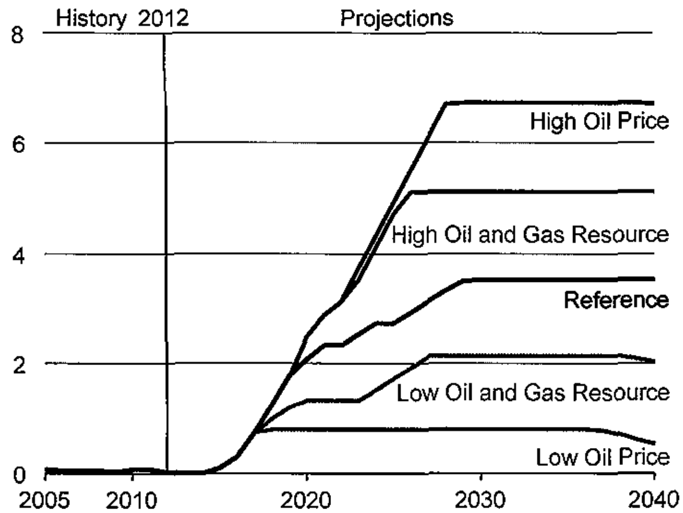
With relatively low natural gas prices in the AEO2014 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports growing to 5.8 Tcf in 2040. Most of the projected growth in exports consists of LNG exported to overseas markets. From 2012 to 2040, U.S. net exports of LNG increase by 3.5 Tcf (Figure MT-45), including 0.8 Tcf of LNG originating in south-central Alaska, with the remaining volumes originating from export terminals located along the Atlantic and Gulf coasts. In general, future U.S. LNG exports depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in U.S. and international gas markets, and the pace of natural gas supply growth outside the United States.

The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

Net natural gas imports from Canada decline through 2033, when they reach a low point of about 0.4 Tcf. After 2033, higher natural gas prices in the lower 48 improve the economics of Canadian natural gas exports to the U.S. West Coast. In 2040, net U.S. imports of natural gas from Canada total about 0.7 Tcf.

LNG export growth depends on price and productivity assumptions

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40 (trillion cubic feet)



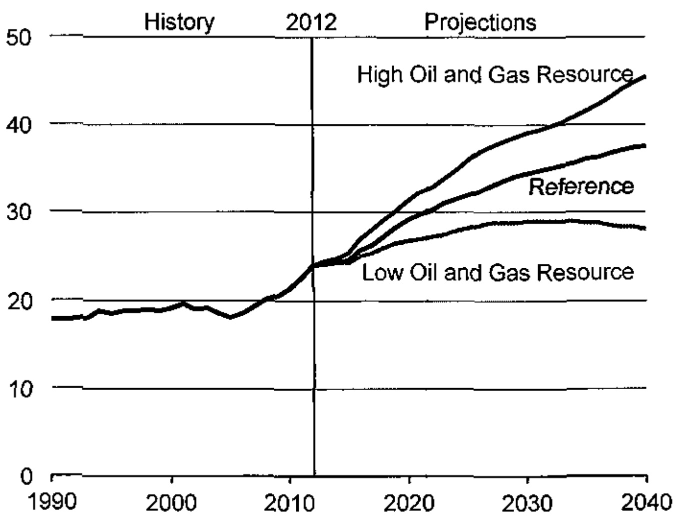
In the AEO2014 Reference case, growing natural gas production from shale gas and tight oil formations supports an increase in U.S. exports of LNG and pipeline gas. Net exports of LNG increase by 3.5 Tcf from 2012 to 2040, representing 48% of the total increase in U.S. natural gas net exports over the period. The United States becomes a net LNG exporter in 2016, with gross exports reaching their peak level of 3.5 Tcf in 2030.

The United States is a net LNG exporter in all of the AEO2014 oil price and resource cases; however, LNG export levels vary significantly by case. In the High Oil Price case, where both global LNG demand and LNG prices are higher than in the Reference case, LNG exports increase to 6.7 Tcf in 2028 and remain at that level through 2040 (Figure MT-46). Conversely, in the Low Oil Price case, gross LNG exports increase to only 0.8 Tcf in 2018, where they remain through most of the projection period. The LNG export projections in AEO2014 are based on a generalized economic evaluation and do not reflect a specific evaluation or knowledge of decisions on pending LNG export applications.

In the High Oil and Gas Resource case, large production increases put downward pressure on U.S. natural gas prices, and as a result LNG exports climb to 5.1 Tcf after 2025. The Low Oil and Gas Resource case assumes lower natural gas production and higher domestic gas prices. Gross LNG exports in the Low Oil and Gas Resource case reach 2.1 Tcf by 2027.

U.S. natural gas production rates depend on resource availability and production costs

Figure MT-47. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



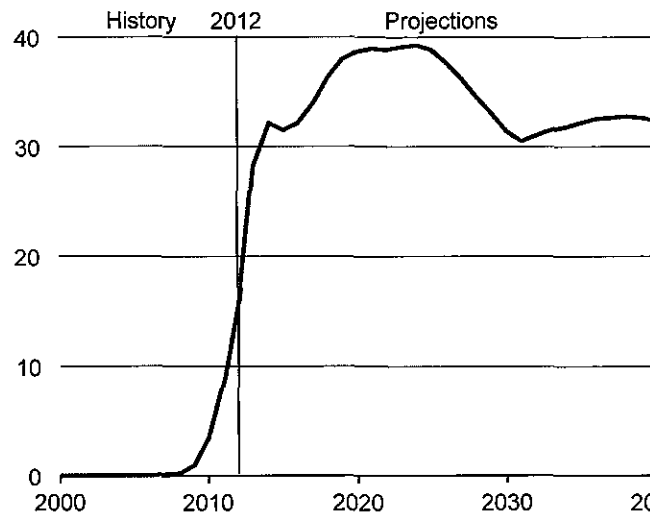
Prospects for production from tight oil and shale gas resources are uncertain, both because large portions of the formations have little or no production history, and because future technology could increase well productivity while reducing costs. The Low Oil and Gas Resource and High Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

The High Oil and Gas Resource case assumes (1) higher estimates of onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case, as a result of higher estimated ultimate recovery (EUR) per well and closer well spacing; (2) tight oil development in Alaska; (3) higher estimates of offshore resources in Alaska and the lower 48 states; and (4) higher rates of long-term technology improvement. In the High Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier resource development than in the Reference case. With the greater abundance of less-expensive shale gas resources, cumulative shale gas production from 2012 through 2040 totals 540 Tcf, as compared with 442 Tcf in the Reference case. In the Reference case and the High Resource case, total natural gas production in 2040 grows to 37.5 Tcf and 45.5 Tcf per year, respectively.

In the Low Oil and Gas Resource case, which assumes lower tight oil, tight gas, and shale gas resources than in the Reference case, total natural gas production plateaus at just under 29 Tcf per year from 2027 through 2036, then declines to 28.1 Tcf in 2040 (Figure MT-47). Shale gas production peaks in 2030 at 13.1 Tcf and declines to 11.6 Tcf in 2040. From 2012 to 2040, cumulative shale gas production totals 341 Tcf in the Low Oil and Gas Resource case.

Marcellus shale gas production growth changes U.S. natural gas transportation patterns

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40 (percent)



Historically, natural gas produced in Texas, Louisiana, Oklahoma, and the offshore Gulf of Mexico has been transported to markets east of the Mississippi River. In addition, significant volumes of natural gas have been transported from Canada and the Rocky Mountains to serve the same markets. However, the advent of large-scale natural gas production in the Marcellus shale formation, located in Appalachia, will alter natural gas transportation patterns east of the Mississippi River.

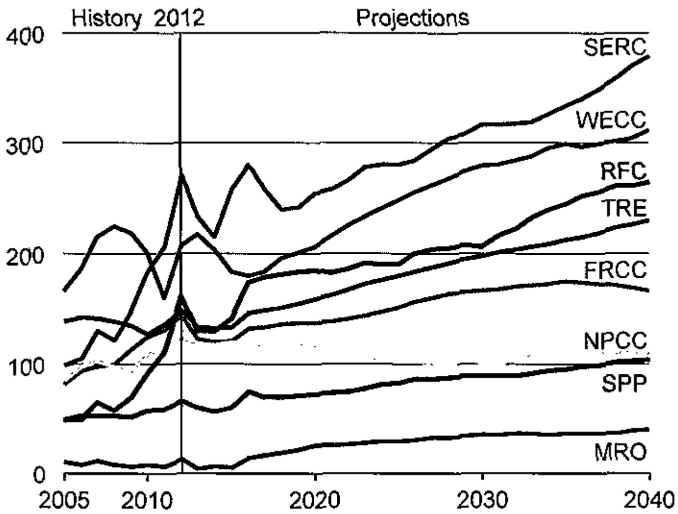
In the AEO2014 Reference Case, natural gas production from the Marcellus shale grows from 1.9 Tcf in 2012 to a peak production volume of about 5.0 Tcf per year from 2022 through 2025. Marcellus shale gas production could provide up to 39% of the natural gas needed to meet demand in markets east of the Mississippi River during that period—up from 16% in 2012. Although Marcellus gas production declines after 2024 in the Reference case, it still provides enough natural gas to meet at least 31% of the region's total demand for natural gas through 2040 (Figure MT-48).

Marcellus natural gas exceeds 100% of the demand projected for the New England and Mid-Atlantic Census Divisions from 2016 through 2040 in the Reference case, requiring transportation of some Marcellus gas to other markets. During the expected peak production period for the Marcellus shale, from 2022 through 2025, its total production exceeds natural gas consumption in the New England and Middle Atlantic regions by more than 1.0 Tcf over the period.

Natural gas consumption

Natural gas-fired generation grows strongly in the electric power sector

Figure MT-49. Natural gas-fired generation in the electric power sector by NERC region in the Reference case, 2005-40 (billion kilowatthours)



Consumption of natural gas by the U.S. electric power sector grows by an average of 0.7%/year from 2012 to 2040 in the AEO2014 Reference case. That growth is equivalent to 42% of the total increase in electricity generation over the period. While the coal-fired share of total generation in the electric power sector declines from 39% in 2012 to 34% in 2040, the natural gas share rises from 29% to 33%.

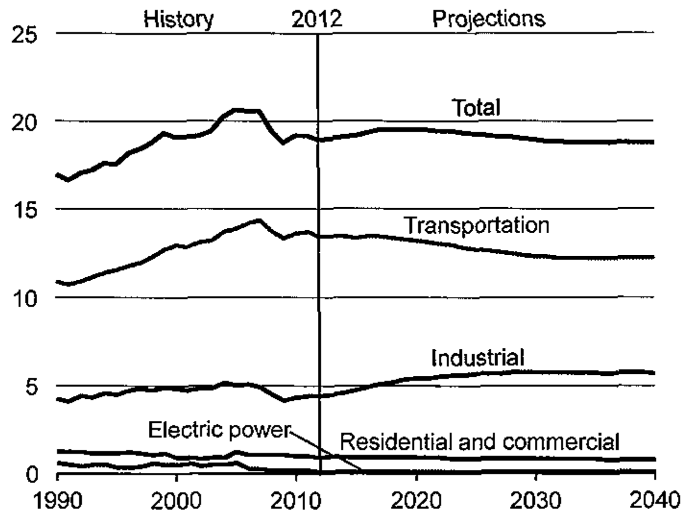
The increase in natural gas-fired generation is generally more pronounced in regions where coal-fired power plants are retired, including the SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC) regions (Figure MT-49). The retirement of coal-fired capacity in the SERC region from 2012 to 2040, at 12.9 GW, is the country's second largest, and its increase in natural gas-fired generation over the same period, at 109 million MWh, is the largest. The largest decrease in coal-fired capacity (21.7 GW) is in the RFC region, which also has the third-largest increase in natural gas-fired generation, at 103 million MWh.

Two other regions with large increases in natural gas-fired generation in the Reference case are the Western Electricity Coordinating Council (WECC) and the Texas Reliability Entity (TRE). Those two regions do not have large retirements of coal-fired generation capacity, but they do have significant overall growth in electricity demand, most of which is met with natural gas-fired generation. WECC has the country's second-largest increase in natural gas-fired generation from 2012 to 2040 (105 million MWh), and TRE has the fourth-largest increase (81 million MWh).

In the RFC and TRE regions, natural gas-fired generation meets the vast majority of growth in electricity demand through 2040. Despite retirements of coal units, coal generation still meets a significant portion of demand in the SERC region. In the WECC region, renewables meet a significant portion of demand growth.

Led by transportation, petroleum and other liquids consumption declines

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040 (million barrels per day)



Consumption of petroleum and other liquids remains relatively flat in volumetric terms in the AEO2014 Reference case (Figure MT-50). While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). In the industrial sector, consumption in the chemicals industry increases by 1.3 million barrels per day (MMbbl/d) from 2012 to 2040, largely reflecting higher volumes of hydrocarbon gas liquids as the sector benefits from increased U.S. production of natural gas. Consumption in all other industry segments decreases between 2012 and 2040.

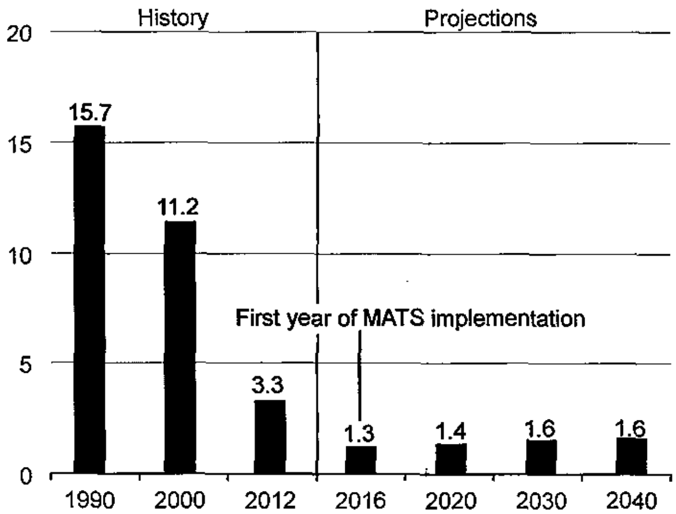
Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, all of which can include biofuels and may be supplemented by natural gas. Total motor gasoline consumption increases from 2012 to 2015 before dropping by approximately 2.1 MMbbl/d from 2015 to 2040 in the Reference case, while total diesel fuel consumption increases from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, primarily for use in HDVs.

Both ethanol blending into gasoline and E85 consumption are essentially flat throughout the projection period, as a result of declining gasoline consumption and limited penetration of FFVs. The rapid rise of U.S. crude oil production, combined with the decline in motor gasoline demand and a modest increase in diesel fuel demand, reduces market opportunities for CTL and GTL technologies.

Emissions from energy use

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure MT-65. Sulfur dioxide emissions from electricity generation in selected years in the Reference case, 1990-2040 (million short tons)



In the AEO2014 Reference case, sulfur dioxide (SO_2) emissions from the electric power sector increase slightly in the early years of the projection but fall rapidly in 2016, when the Mercury and Air Toxics Standards (MATS) [*18*] are fully implemented.

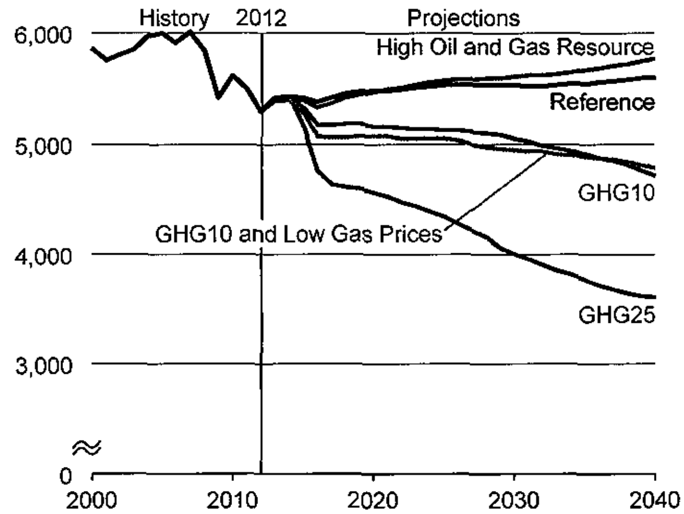
The Reference case assumes that all coal-fired power plants operating in the United States will be equipped with either flue gas desulfurization units (scrubbers) or dry sorbent injection (DSI) systems by 2016 to comply with the specific requirements of MATS. The emissions controls have the ancillary benefit of removing significant amounts of SO_2. For example, scrubbers remove more than 90% of SO_2 emissions from flue gas. DSI systems, when combined with fabric filters, remove approximately 70% of SO_2 emissions.

At the end of 2012, 64% of electric power sector coal-fired generating capacity in the United States already had either scrubbers or DSI systems installed. The Reference case assumes that by 2016, every operating coal plant in the United States larger than 25 megawatts has some type of control equipment, including approximately 31 GW of coal-fired capacity retrofitted with scrubbers and another 45 GW retrofitted with DSI systems.

After a 61% decrease from 2012 to 2016 (Figure MT-65), annual SO_2 emissions increase by 0.9%/year from 2016 to 2040, as total electricity generation from coal-fired power plants increases by 0.3%/year, and scrubbers and DSI equipment remove most (but not all) SO_2 from flue gas. As a result of MATS compliance, SO_2 emissions are reduced to a level below the cap specified in the Clean Air Interstate Rule (CAIR).

Energy-related carbon dioxide emissions are sensitive to potential policy changes

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)



Although the AEO2014 Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of future policies that would place an implicit or explicit value on CO_2 emissions are examined in two cases, starting at $10 (GHG10) and $25 (GHG25) per metric ton CO_2 in 2015 and rising by 5% per year thereafter. Because of uncertainty about the growing role of natural gas in the U.S. energy landscape and how it might affect efforts to reduce GHG emissions, the $10 fee case was run both with the Reference case and combined with the High Oil and Gas Resource case (GHG10 and Low Gas Prices) (Figure MT-66).

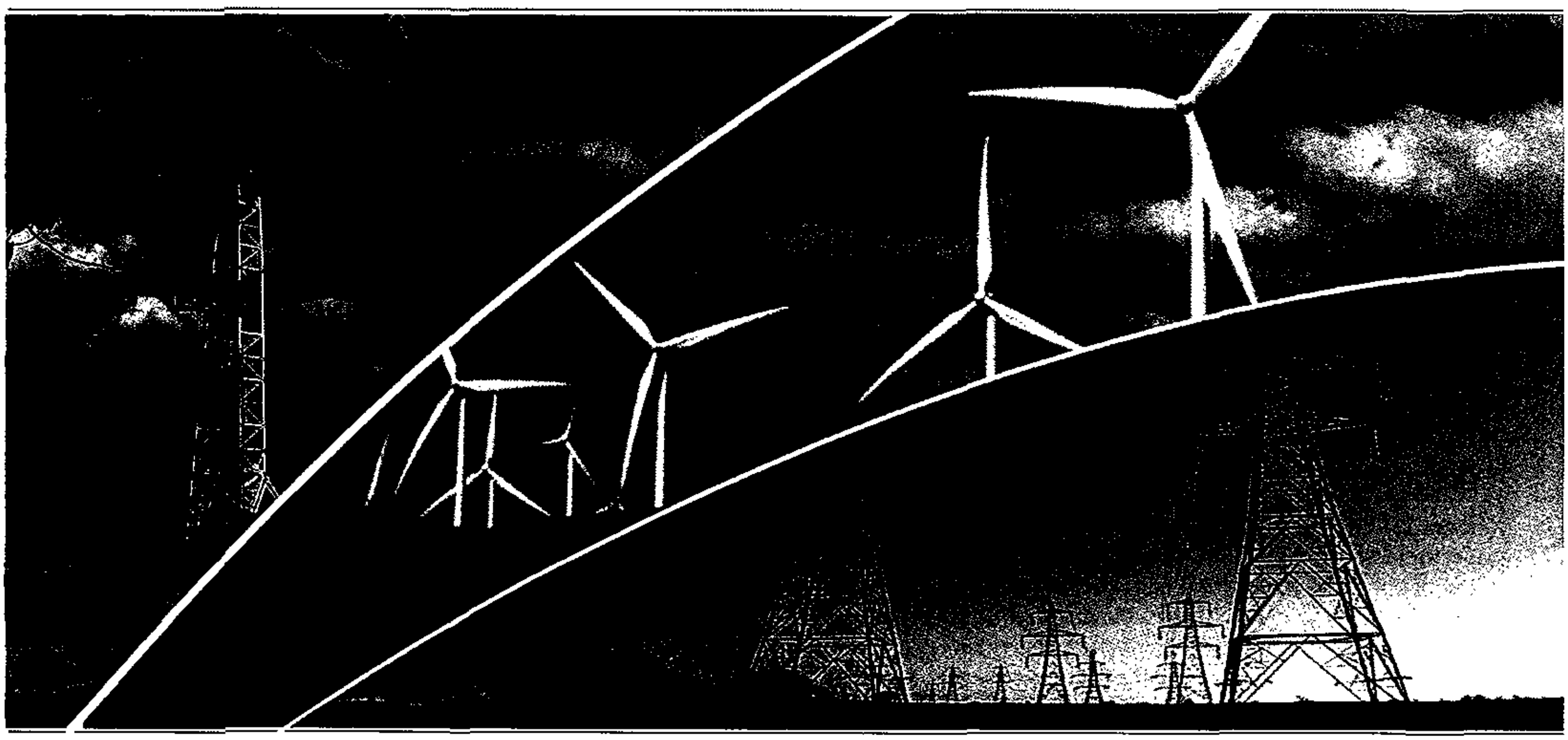
Emissions fees or other policies that place an explicit or implicit value on CO_2 emissions would encourage all energy producers and consumers to shift to lower-carbon or zero-carbon energy sources. Relative to 2005 emissions levels, energy-related CO_2 emissions are 15% and 28% lower in 2025 in the GHG10 and GHG25 cases using Reference case resources, respectively, and 22% and 40% lower in 2040. When combined with High Oil and Gas Resource assumptions, the CO_2 fees in the GHG10 case tend to lead to slightly greater emissions reductions in the near term and smaller reductions in the long term.

The alternative assumptions about natural gas resources have only small impacts on energy-related CO_2 emissions in the GHG10 and Low Gas Prices case. Although more abundant and less expensive natural gas in the High Oil and Gas Resource cases does lead to less coal use and more natural gas use, it also reduces the use of renewable and nuclear fuels and increases energy consumption overall. Shortly after 2020, the emissions reductions achieved by shifting from coal to natural gas are offset by the impacts of reduced use of renewables and nuclear power for electricity generation, and by higher overall levels of energy consumption.

DOE/EIA-0383(2014) | April 2014

Annual Energy Outlook 2014

with projections to 2040

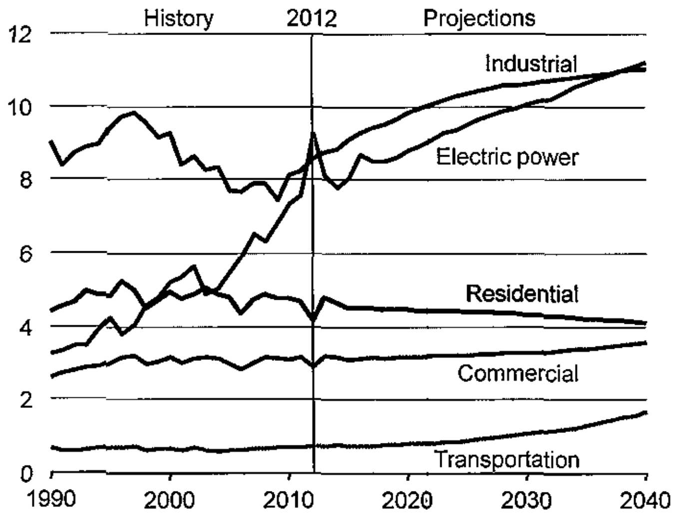


Independent Statistics & Analysis

U.S. Energy Information Administration

Industrial and electric power sectors drive growth in U.S. natural gas consumption

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040 (trillion cubic feet)



U.S. total natural gas consumption grows from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040 in the AEO2014 Reference case. Natural gas use increases in all of the end-use sectors except residential (Figure MT-39). Natural gas use for residential space heating declines as a result of population shifts to warmer regions of the country and improvements in appliance efficiency.

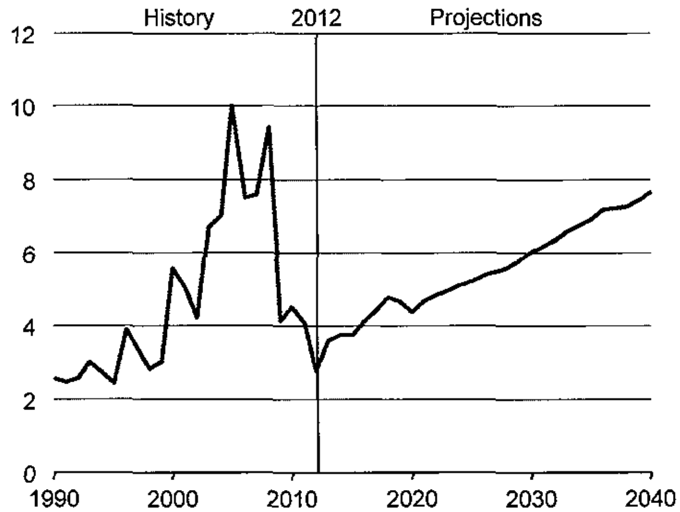
Consumption of natural gas for electric power generation grows by about 2 Tcf and makes up about 33% of the increase in total natural gas consumption by 2040. Relatively low natural gas prices make natural gas an attractive fuel for serving increased load. Natural gas is also the fuel most often used to replace older coal-fired generation as it is retired.

From 2012 to 2040, natural gas consumption in the industrial sector increases by 2.5 Tcf, an average of 0.9%/year, representing about 26% of the total increase in natural gas consumption. As industrial output grows, the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2028. After 2028, industrial sector consumption of natural gas continues to grow but at a somewhat slower rate, in response to rising prices.

Although transportation use currently accounts for only a small portion of total U.S. natural gas consumption, natural gas use by heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection. Consumption in the transportation sector, excluding natural gas use at compressor stations, grows from about 40 billion cubic feet (Bcf) in 2012 to 850 Bcf in 2040.

Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)



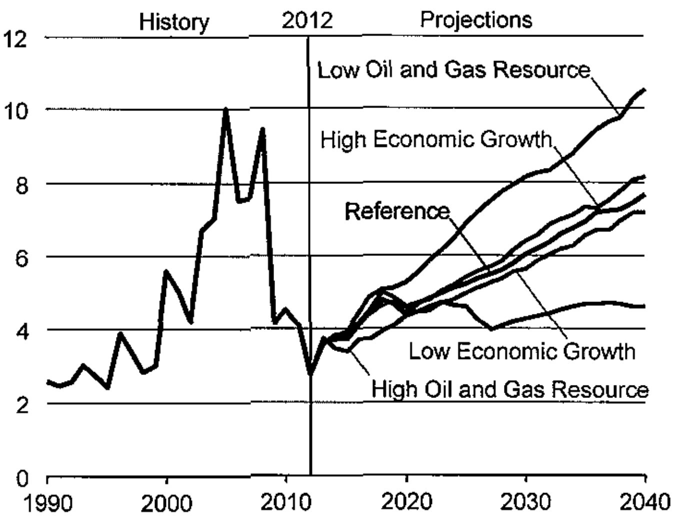
Average annual U.S. natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies. To provide the supplies necessary to meet growth in natural gas consumption and a rise in exports in the AEO2014 Reference case, producers move into areas where the recovery of natural gas is more difficult and expensive, which leads to an increase in Henry Hub spot prices over the projection period. Henry Hub spot prices for natural gas increase by an average of 3.7%/year in the Reference case, from $2.75/million Btu (MMBtu) in 2012 to $7.65/MMBtu (2012 dollars) in 2040 (Figure MT-40).

Growth in demand for natural gas, largely from the electric power and industrial sectors and for liquefied natural gas (LNG) exports, results in upward pressure on prices, particularly in the 2015-18 period. Delivered prices to residential, commercial, industrial, and electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in areas that do not serve the Henry Hub is somewhat faster than growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. Total onshore production in the Northeast region grows on average by 3.2%/year, from 3.3 Tcf in 2012 to 8.1 Tcf in 2040, while combined onshore and offshore production in the Gulf region grows by 2.1%/year, from 7.3 Tcf in 2012 to 13.0 Tcf in 2040.

Natural gas prices

Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



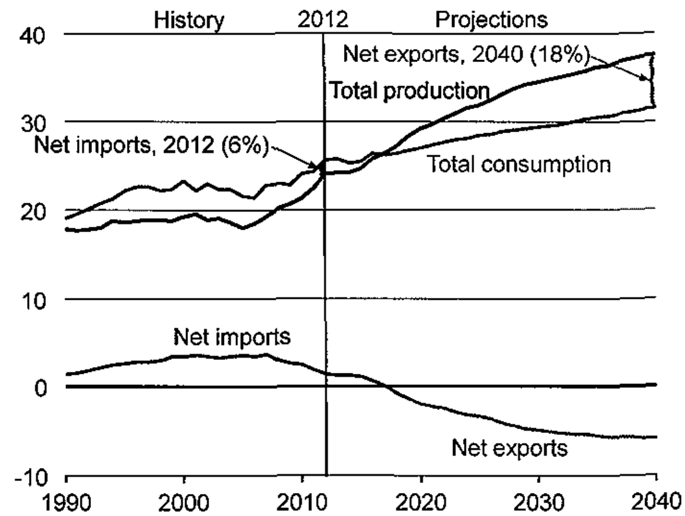
The projection of natural gas prices depends on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas, primarily in response to their effects on housing starts, commercial floorspace, and industrial output. In the High Economic Growth case, higher levels of consumption result in more rapid increases both in depletion of natural gas resources and in the cost of developing new production, pushing natural gas prices higher. The converse is true in the Low Economic Growth case (Figure MT-41). In the High and Low Economic Growth cases, the price rises by 4.0%/year and 3.5%/year, respectively, compared with 3.7%/year in the Reference case.

The rate of resource recovery from oil and natural gas wells has a direct impact on the cost per unit of production and, in turn, prices. The High Oil and Gas Resource case assumes higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska than in the Reference case. The Low Oil and Gas Resource case assumes lower estimated ultimate recovery of natural gas from each shale well or tight well than in the Reference case. In the Low and High Oil and Gas Resource cases, Henry Hub spot natural gas prices increase by 4.9%/year and 1.8%/year, respectively. (An article in the Issues in focus section, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," provides more information on the alternative resource cases.)

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to increases in natural gas exports and demand, which place some upward pressure on natural gas prices.

With production growing faster than use, the U.S. becomes a net exporter of natural gas

Figure MT-42. Total natural gas production, consumption, and imports in the Reference case, 1990-2040 (trillion cubic feet)



In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.

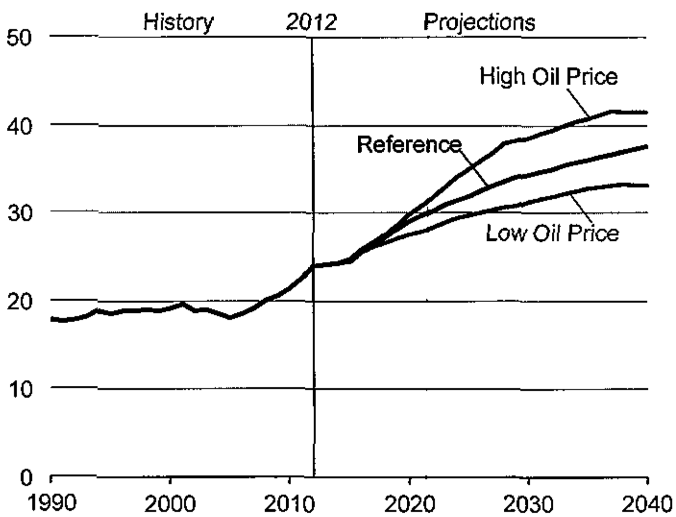
The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors. Growing LNG exports also support higher natural gas prices.

The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).

Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico. Net pipeline imports from Canada drop from 2.0 Tcf in 2012 to 0.4 Tcf in 2030, mainly as a result of lower imports to the western United States. Imports from Canada increase to 0.7 Tcf in 2040, with higher imports into the northeastern United States. In contrast, net pipeline exports to Mexico grow steadily, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040.

U.S. natural gas production, use, and exports all are affected by oil prices

Figure MT-43. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



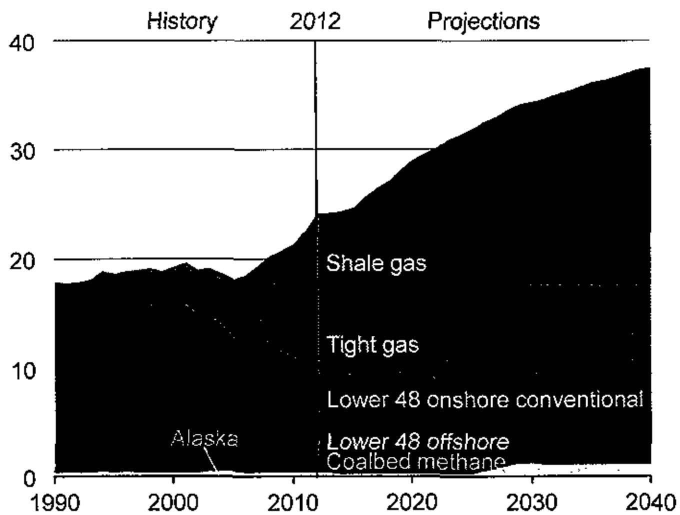
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the oil price cases, the largest changes in consumption are seen for natural gas consumed in transportation and natural gas exported as LNG.

The profitability of natural gas as a transportation fuel or as LNG for export depends primarily on the price differential between crude oil and natural gas. For example, in the Low Oil Price case, the average difference between oil prices and natural gas prices from 2012 through 2040 is about $7.70 per million Btu (MMBtu). With that low price differential, virtually no natural gas is consumed in the transportation sector, and little LNG is exported. In the High Oil Price case, in contrast, the average price difference is about $21.90/MMBtu, which provides substantial incentive for direct use of natural gas in transportation and for conversion to LNG for export.

Across the oil price cases, total natural gas production varies by 8.3 Tcf in 2040 (Figure MT-43), with changes in LNG exports accounting for 6.3 Tcf and changes in direct consumption for transportation accounting for 2.2 Tcf. The increase in LNG exports and transportation consumption is offset to some extent by lower natural gas consumption in other sectors, with spot prices for natural gas from 2012 to 2040 averaging about $0.70/MMBtu higher in the High Oil Price case than in the Low Oil Price case.

Shale gas provides the largest source of growth in U.S. natural gas supply

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)



The 56% increase in total natural gas production from 2012 to 2040 in the AEO2014 Reference Case results from increased development of shale gas, tight gas, and offshore natural gas resources (Figure MT-44). Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production increases from 40% in 2012 to 53% in 2040. Tight gas production and offshore gas production increase by 73% and 78%, respectively, from 2012 to 2040, but their shares of total production remain relatively constant.

From 2017 to 2022, U.S. offshore natural gas production declines by 0.3 Tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 Tcf in 2040, as natural gas prices rise.

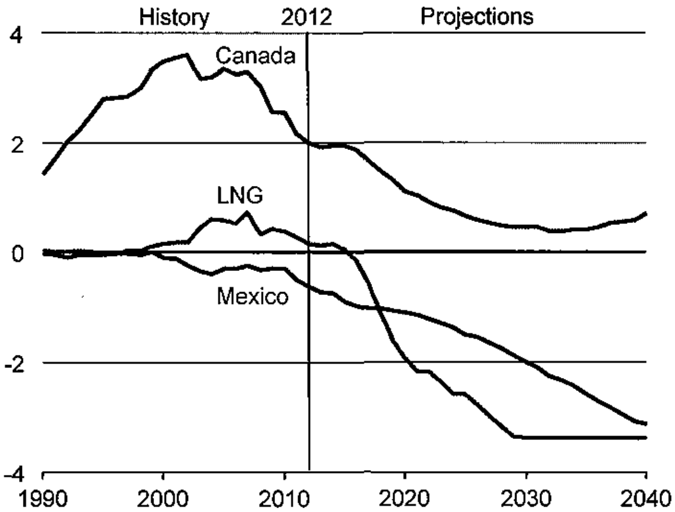
Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 Tcf (2.2 Bcf/d) in 2029. Alaska's LNG exports level off at 0.8 Tcf per year over the last decade of the projec-tion. Alaska's total natural gas production in 2040 is 1.2 Tcf.

Although U.S. natural gas production rises throughout the projection, the mix of sources changes over time. Onshore nonassociated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 Tcf in 2012 to 1.6 Tcf in 2040, and in 2040 it accounts for only about 4% of total domestic production, down from 16% in 2012.

Natural gas trade

U.S. exports to North American and overseas gas markets increase as gas production rises

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040 (trillion cubic feet)



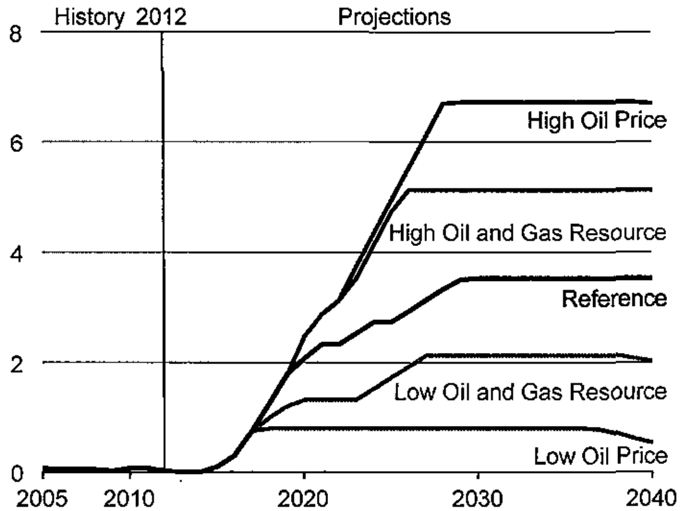
With relatively low natural gas prices in the AEO2014 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports growing to 5.8 Tcf in 2040. Most of the projected growth in exports consists of LNG exported to overseas markets. From 2012 to 2040, U.S. net exports of LNG increase by 3.5 Tcf (Figure MT-45), including 0.8 Tcf of LNG originating in south-central Alaska, with the remaining volumes originating from export terminals located along the Atlantic and Gulf coasts. In general, future U.S. LNG exports depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in U.S. and international gas markets, and the pace of natural gas supply growth outside the United States.

The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

Net natural gas imports from Canada decline through 2033, when they reach a low point of about 0.4 Tcf. After 2033, higher natural gas prices in the lower 48 improve the economics of Canadian natural gas exports to the U.S. West Coast. In 2040, net U.S. imports of natural gas from Canada total about 0.7 Tcf.

LNG export growth depends on price and productivity assumptions

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40 (trillion cubic feet)



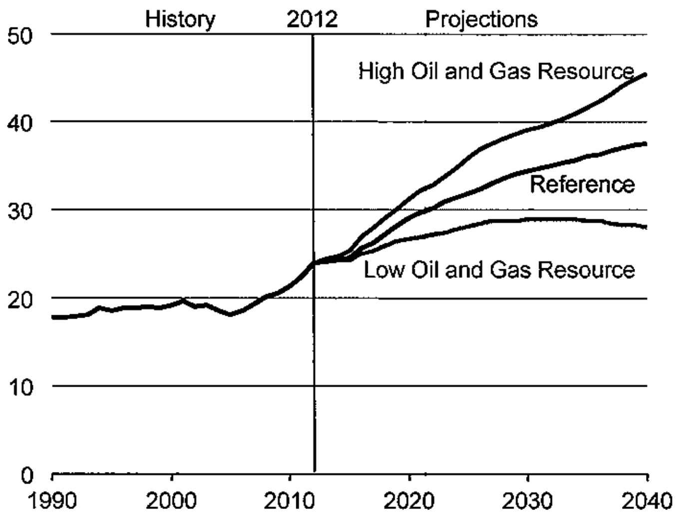
In the AEO2014 Reference case, growing natural gas production from shale gas and tight oil formations supports an increase in U.S. exports of LNG and pipeline gas. Net exports of LNG increase by 3.5 Tcf from 2012 to 2040, representing 48% of the total increase in U.S. natural gas net exports over the period. The United States becomes a net LNG exporter in 2016, with gross exports reaching their peak level of 3.5 Tcf in 2030.

The United States is a net LNG exporter in all of the AEO2014 oil price and resource cases; however, LNG export levels vary significantly by case. In the High Oil Price case, where both global LNG demand and LNG prices are higher than in the Reference case, LNG exports increase to 6.7 Tcf in 2028 and remain at that level through 2040 (Figure MT-46). Conversely, in the Low Oil Price case, gross LNG exports increase to only 0.8 Tcf in 2018, where they remain through most of the projection period. The LNG export projections in AEO2014 are based on a generalized economic evaluation and do not reflect a specific evaluation or knowledge of decisions on pending LNG export applications.

In the High Oil and Gas Resource case, large production increases put downward pressure on U.S. natural gas prices, and as a result LNG exports climb to 5.1 Tcf after 2025. The Low Oil and Gas Resource case assumes lower natural gas production and higher domestic gas prices. Gross LNG exports in the Low Oil and Gas Resource case reach 2.1 Tcf by 2027.

U.S. natural gas production rates depend on resource availability and production costs

Figure MT-47. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



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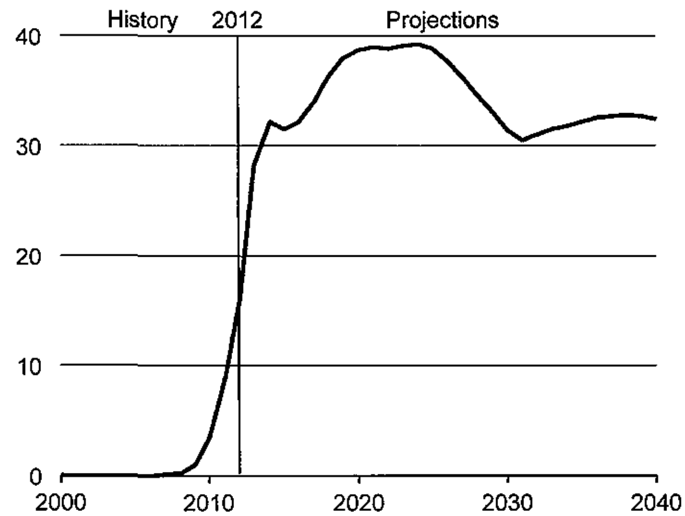
Marcellus shale gas production growth changes U.S. natural gas transportation patterns

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40 (percent)



Historically, natural gas produced in Texas, Louisiana, Oklahoma, and the offshore Gulf of Mexico has been transported to markets east of the Mississippi River. In addition, significant volumes of natural gas have been transported from Canada and the Rocky Mountains to serve the same markets. However, the advent of large-scale natural gas production in the Marcellus shale formation, located in Appalachia, will alter natural gas transportation patterns east of the Mississippi River.

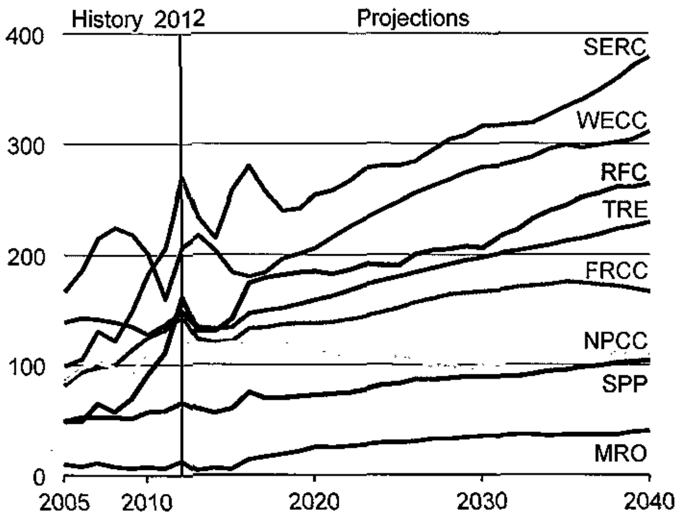
In the AEO2014 Reference Case, natural gas production from the Marcellus shale grows from 1.9 Tcf in 2012 to a peak production volume of about 5.0 Tcf per year from 2022 through 2025. Marcellus shale gas production could provide up to 39% of the natural gas needed to meet demand in markets east of the Mississippi River during that period—up from 16% in 2012. Although Marcellus gas production declines after 2024 in the Reference case, it still provides enough natural gas to meet at least 31% of the region's total demand for natural gas through 2040 (Figure MT-48).

Marcellus natural gas exceeds 100% of the demand projected for the New England and Mid-Atlantic Census Divisions from 2016 through 2040 in the Reference case, requiring transportation of some Marcellus gas to other markets. During the expected peak production period for the Marcellus shale, from 2022 through 2025, its total production exceeds natural gas consumption in the New England and Middle Atlantic regions by more than 1.0 Tcf over the period.

Natural gas consumption

Natural gas-fired generation grows strongly in the electric power sector

Figure MT-49. Natural gas-fired generation in the electric power sector by NERC region in the Reference case, 2005-40 (billion kilowatthours)



Consumption of natural gas by the U.S. electric power sector grows by an average of 0.7%/year from 2012 to 2040 in the AEO2014 Reference case. That growth is equivalent to 42% of the total increase in electricity generation over the period. While the coal-fired share of total generation in the electric power sector declines from 39% in 2012 to 34% in 2040, the natural gas share rises from 29% to 33%.

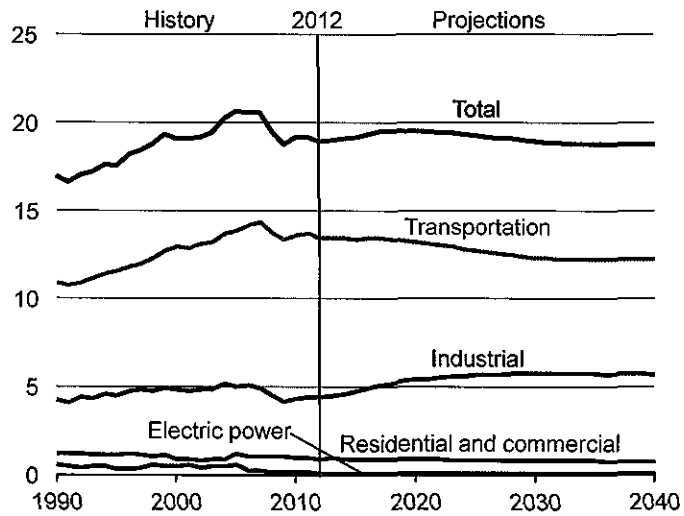
The increase in natural gas-fired generation is generally more pronounced in regions where coal-fired power plants are retired, including the SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC) regions (Figure MT-49). The retirement of coal-fired capacity in the SERC region from 2012 to 2040, at 12.9 GW, is the country's second largest, and its increase in natural gas-fired generation over the same period, at 109 million MWh, is the largest. The largest decrease in coal-fired capacity (21.7 GW) is in the RFC region, which also has the third-largest increase in natural gas-fired generation, at 103 million MWh.

Two other regions with large increases in natural gas-fired generation in the Reference case are the Western Electricity Coordinating Council (WECC) and the Texas Reliability Entity (TRE). Those two regions do not have large retirements of coal-fired generation capacity, but they do have significant overall growth in electricity demand, most of which is met with natural gas-fired generation. WECC has the country's second-largest increase in natural gas-fired generation from 2012 to 2040 (105 million MWh), and TRE has the fourth-largest increase (81 million MWh).

In the RFC and TRE regions, natural gas-fired generation meets the vast majority of growth in electricity demand through 2040. Despite retirements of coal units, coal generation still meets a significant portion of demand in the SERC region. In the WECC region, renewables meet a significant portion of demand growth.

Led by transportation, petroleum and other liquids consumption declines

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040 (million barrels per day)



Consumption of petroleum and other liquids remains relatively flat in volumetric terms in the AEO2014 Reference case (Figure MT-50). While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). In the industrial sector, consumption in the chemicals industry increases by 1.3 million barrels per day (MMbbl/d) from 2012 to 2040, largely reflecting higher volumes of hydrocarbon gas liquids as the sector benefits from increased U.S. production of natural gas. Consumption in all other industry segments decreases between 2012 and 2040.

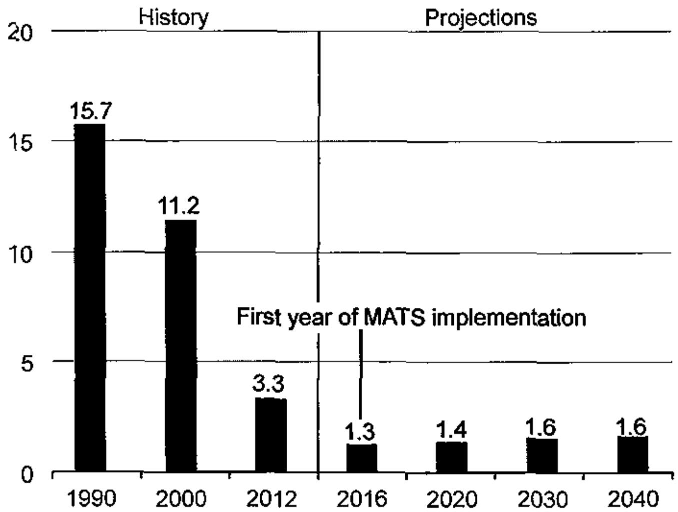
Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, all of which can include biofuels and may be supplemented by natural gas. Total motor gasoline consumption increases from 2012 to 2015 before dropping by approximately 2.1 MMbbl/d from 2015 to 2040 in the Reference case, while total diesel fuel consumption increases from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, primarily for use in HDVs.

Both ethanol blending into gasoline and E85 consumption are essentially flat throughout the projection period, as a result of declining gasoline consumption and limited penetration of FFVs. The rapid rise of U.S. crude oil production, combined with the decline in motor gasoline demand and a modest increase in diesel fuel demand, reduces market opportunities for CTL and GTL technologies.

Emissions from energy use

Power plant emissions of sulfur dioxide are reduced by further environmental controls

Figure MT-65. Sulfur dioxide emissions from electricity generation in selected years in the Reference case, 1990-2040 (million short tons)



In the AEO2014 Reference case, sulfur dioxide (SO_2) emissions from the electric power sector increase slightly in the early years of the projection but fall rapidly in 2016, when the Mercury and Air Toxics Standards (MATS) *[18]* are fully implemented.

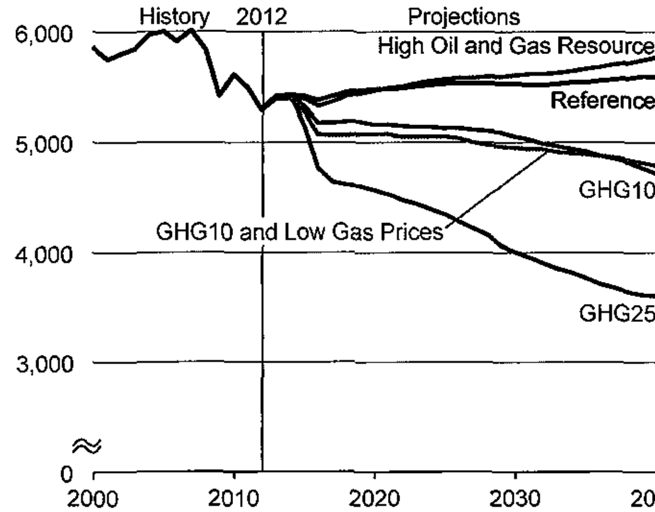
The Reference case assumes that all coal-fired power plants operating in the United States will be equipped with either flue gas desulfurization units (scrubbers) or dry sorbent injection (DSI) systems by 2016 to comply with the specific requirements of MATS. The emissions controls have the ancillary benefit of removing significant amounts of SO_2. For example, scrubbers remove more than 90% of SO_2 emissions from flue gas. DSI systems, when combined with fabric filters, remove approximately 70% of SO_2 emissions.

At the end of 2012, 64% of electric power sector coal-fired generating capacity in the United States already had either scrubbers or DSI systems installed. The Reference case assumes that by 2016, every operating coal plant in the United States larger than 25 megawatts has some type of control equipment, including approximately 31 GW of coal-fired capacity retrofitted with scrubbers and another 45 GW retrofitted with DSI systems.

After a 61% decrease from 2012 to 2016 (Figure MT-65), annual SO_2 emissions increase by 0.9%/year from 2016 to 2040, as total electricity generation from coal-fired power plants increases by 0.3%/year, and scrubbers and DSI equipment remove most (but not all) SO_2 from flue gas. As a result of MATS compliance, SO_2 emissions are reduced to a level below the cap specified in the Clean Air Interstate Rule (CAIR).

Energy-related carbon dioxide emissions are sensitive to potential policy changes

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)



Although the AEO2014 Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of future policies that would place an implicit or explicit value on CO_2 emissions are examined in two cases, starting at \$10 (GHG10) and \$25 (GHG25) per metric ton CO_2 in 2015 and rising by 5% per year thereafter. Because of uncertainty about the growing role of natural gas in the U.S. energy landscape and how it might affect efforts to reduce GHG emissions, the \$10 fee case was run both with the Reference case and combined with the High Oil and Gas Resource case (GHG10 and Low Gas Prices) (Figure MT-66).

Emissions fees or other policies that place an explicit or implicit value on CO_2 emissions would encourage all energy producers and consumers to shift to lower-carbon or zero-carbon energy sources. Relative to 2005 emissions levels, energy-related CO_2 emissions are 15% and 28% lower in 2025 in the GHG10 and GHG25 cases using Reference case resources, respectively, and 22% and 40% lower in 2040. When combined with High Oil and Gas Resource assumptions, the CO_2 fees in the GHG10 case tend to lead to slightly greater emissions reductions in the near term and smaller reductions in the long term.

The alternative assumptions about natural gas resources have only small impacts on energy-related CO_2 emissions in the GHG10 and Low Gas Prices case. Although more abundant and less expensive natural gas in the High Oil and Gas Resource cases does lead to less coal use and more natural gas use, it also reduces the use of renewable and nuclear fuels and increases energy consumption overall. Shortly after 2020, the emissions reductions achieved by shifting from coal to natural gas are offset by the impacts of reduced use of renewables and nuclear power for electricity generation, and by higher overall levels of energy consumption.

U.S. Energy Information Administration

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PENGAD 800-631-6989
IGS
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Analysis & Projections
World Shale Resource Assessments

Last updated: September 24, 2015

This series of reports provides an initial assessment of world shale oil and shale gas resources. The first edition was released in 2011 and updates are released on an on-going basis. Four countries were added in 2014: Chad, Kazakhstan, Oman and the United Arab Emirates (UAE) and are available as supplemental chapters to the 2013 report Technically Recoverable Shale Oil and Shale Gas Resources.

The most current version of each country chapter is linked in the table of countries below. Archived editions are provided in links in the sidebar column to the right.

Countries assessed by date

		Unproved technically recoverable		
Region	Country	wet shale gas (trillion cubic feet)	tight oil (billion barrels)	Date updated
North America				
	Canada	572.9	8.8	5/17/13
	Mexico	545.2	13.1	5/17/13
	U.S.[1]	622.5	78.2	4/14/15
Australia				
	Australia[2]	429.3	15.6	5/17/13
South America				
	Argentina	801.5	27.0	5/17/13
	Bolivia	36.4	0.6	5/17/13
	Brazil	244.9	5.3	5/17/13
	Chile	48.5	2.3	5/17/13
	Colombia	54.7	6.8	5/17/13
	Paraguay	75.3	3.7	5/17/13
	Uruguay[3]	4.6	0.6	5/17/13
	Venezuela	167.3	13.4	5/17/13
Eastern Europe				
	Bulgaria	16.6	0.2	5/17/13
	Lithuania/Kaliningrad	2.4	1.4	5/17/13
	Poland	145.8	1.8	5/17/13
	Romania	50.7	0.3	5/17/13
	Russia	284.5	74.6	5/17/13
	Turkey	23.6	4.7	5/17/13
	Ukraine	127.9	1.1	5/17/13
Western Europe				
	Denmark	31.7	0.0	5/17/13
	France	136.7	4.7	5/17/13

	Germany	17.0	0.7	5/17/13
	Netherlands	25.9	2.9	5/17/13
	Norway	0.0	0.0	5/17/13
	Spain	8.4	0.1	5/17/13
	Sweden	9.8	0.0	5/17/13
	United Kingdom	25.8	0.7	5/17/13
North Africa				
	Algeria	706.9	5.7	5/17/13
	Egypt	100.0	4.6	5/17/13
	Libya	121.6	26.1	5/17/13
	Mauritania	0.0	0.0	5/17/13
	Morocco	11.9	0.0	5/17/13
	Tunisia	22.7	1.5	5/17/13
	West Sahara	8.6	0.2	5/17/13
Sub-Saharan Africa				
	Chad	44.4	16.2	12/29/14
	South Africa	389.7	0.0	5/17/13
Asia				
	China	1115.2	32.2	5/17/13
	India	96.4	3.8	5/17/13
	Indonesia	46.4	7.9	5/17/13
	Mongolia	4.4	3.4	5/17/13
	Pakistan	105.2	9.1	5/17/13
	Thailand	5.4	0.0	5/17/13
Caspian				
	Kazakhstan	27.5	10.6	12/29/14
Middle East				
	Jordan	6.8	0.1	5/17/13
	Oman	48.3	6.2	12/29/14
	United Arab Emirates	205.3	22.6	12/29/14
46 Countries' total		**7,576.6**	**418.9**	

bbl = barrels; Tcf = trillion cubic feet.

[1] 1Includes data from U.S. Geological Survey, Assessment of Potential Oil and Gas Resources in Source Rocks of the Alaska North Slope, Fact Sheet 2012-3013, February 2012.

U.S. Energy Information Administration, Annual Energy Outlook 2015 Assumptions Report. Table 9.3 used for tight oil and Table 9.2 dry unproved natural gas (shale gas) resource estimate was multiplied by 1.045 so as to include natural gas plant liquids for an unproved wet natural gas volume.

[2,3] Corrected data inaccuracy in EIA/ARI 2013 world shale report. See Attachment A.

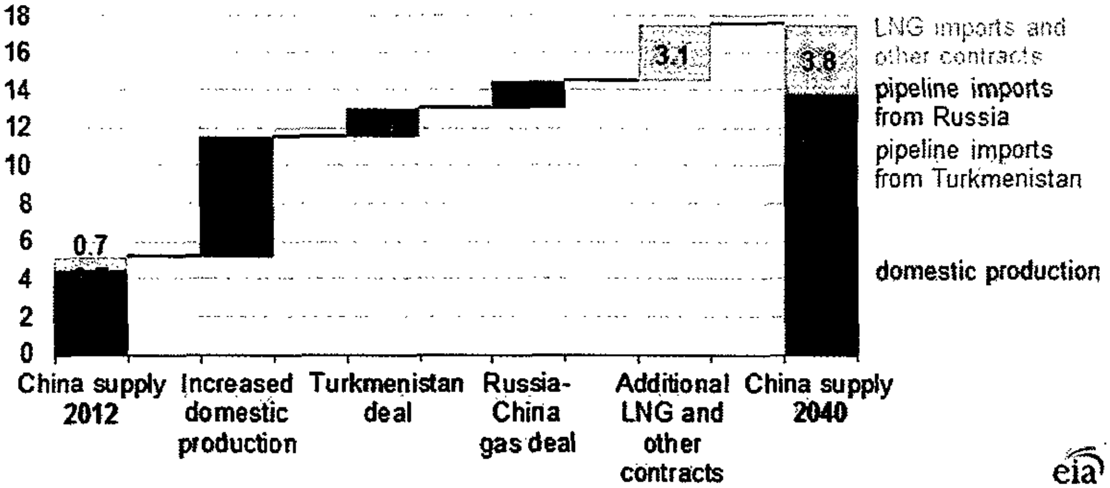
U.S. Energy Information Administration

Today in Energy

August 20, 2014

Russia-China deal will supply Siberian natural gas to China's northern, eastern provinces

Chinese natural gas supply mix (2012-40)
trillion cubic feet



Source: U.S. Energy Information Administration, International Energy Outlook 2013, IHS Energy, Eastern Bloc Research
Note: Volumes shown for Russia-China gas deal assume minimal contract obligations. Increases in these volumes will lessen the amount needed from LNG imports and other contracts.

China's natural gas demand has been growing as the government seeks to move away from coal in favor of cleaner fuels. According to EIA's *International Energy Outlook 2013* (IEO2013) Reference case, demand will more than triple from 5.2 Tcf in 2012 to 17.5 Tcf by 2040.

Russia's largest natural gas company, Gazprom, finalized a deal with the Chinese National Petroleum Corporation (CNPC) in May. Under the first phase of the new 30-year contract, Russia will supply China 38 billion cubic meters (bcm), or 1.3 trillion cubic feet (Tcf), per year of natural gas starting in 2018. Future phases could increase this volume to as much as 60 bcm (2.1 Tcf) per year. The contract links the natural gas price to international crude oil prices and operates as a take-or-pay scheme: the buyer, CNPC, must pay for the contracted natural gas even if it decides not to receive it.

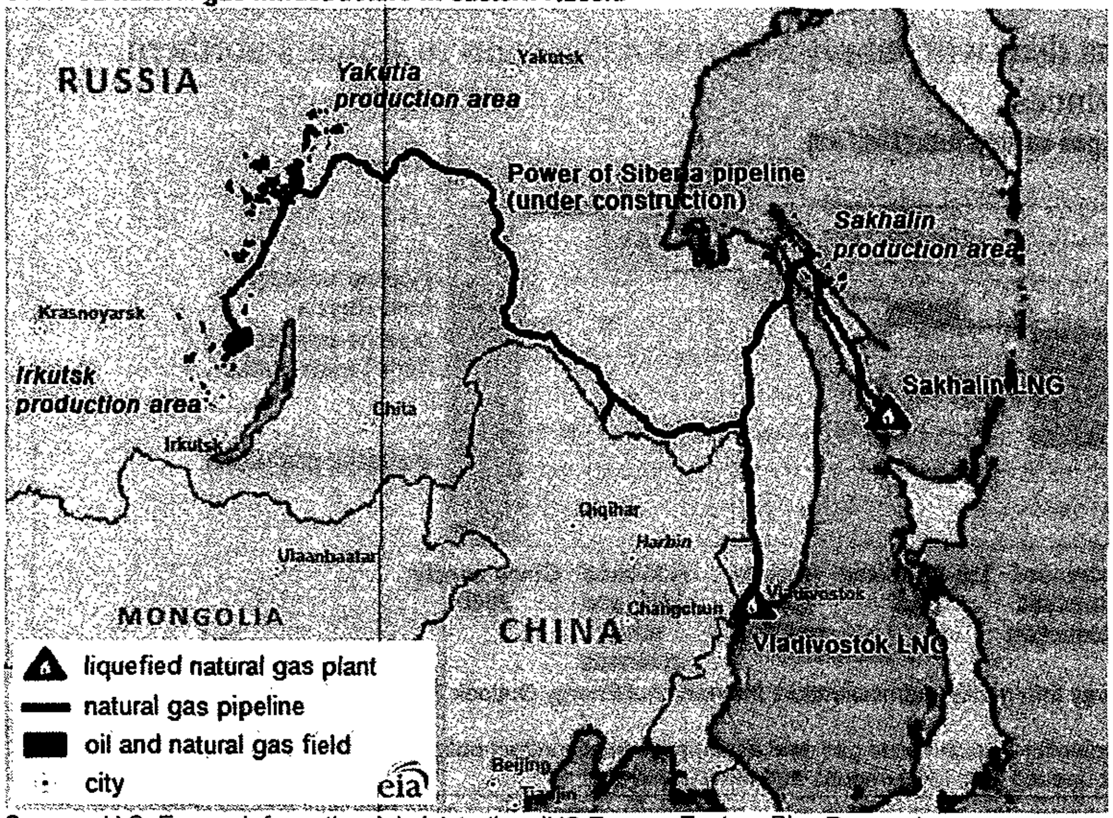
New natural gas production in Russia will mainly come from fields in eastern Siberia, which currently lack export infrastructure. The planned Power of Siberia pipeline will export gas south to China and east to a liquefied natural gas (LNG) plant on Russia's east coast.

This contract is Gazprom's largest to date. Gazprom has a monopoly on pipeline natural gas export contracts made by Russia. The situation differs from that in LNG markets, where other companies such as Rosneft and Novatek may participate.

China's northern and eastern provinces have growing natural gas demand that cannot be met by existing pipelines or LNG, and the new Russian natural gas will mostly go to meet demand in these regions. China has also committed to purchasing 38 bcm (1.3 Tcf) per year of natural gas from Turkmenistan by 2016, increasing to 65 bcm (2.2Tcf) per year by 2020.

Although China continues to import more LNG, the government is committed to expanding Chinese domestic production, which increases from 4 Tcf in 2012 to 10 Tcf by 2040 in the IEO2013 Reference case. Developing China's shale gas reserves is also an important part of the government's natural gas strategy. According to EIA's assessment of world shale gas resources, China has 1,115 Tcf of technically recoverable shale gas. New production along with imports of LNG will meet rising demand in China's eastern and southern coastal regions.

Selected natural gas infrastructure in eastern Russia



Source: U.S. Energy Information Administration, IHS Energy, Eastern Bloc Research

Principal contributor: Alexander Metelitsa

Futures Daily Market Report for Henry Hub
21-Oct-2015

H-Henry LD1 Fixed Price Future														
H	Nov15	2.490	2.490	2.379	2.391	2.404	-0.072	186,727	256,961	4,081	0	0	10,325	50,433
H	Dec15	2.685	2.685	2.584	2.591	2.603	-0.068	96,797	384,752	7,312	0	0	7,816	54,215
H	Jan16	2.812	2.812	2.734	2.743	2.750	-0.065	46,592	324,852	1,552	0	0	4,837	29,789
H	Feb16	2.822	2.822	2.747	2.755	2.762	-0.063	19,074	172,469	-2,734	0	0	2,774	10,523
H	Mar16	2.775	2.775	2.723	2.729	2.736	-0.059	37,648	250,118	-5,887	0	0	2,540	28,912
H	Apr16	2.650	2.655	2.619	2.630	2.636	-0.037	52,020	241,064	-3,747	0	400	8,960	36,176
H	May16	2.669	2.669	2.636	2.650	2.653	-0.034	13,697	147,667	1,127	0	400	2,325	7,511
H	Jun16	2.695	2.695	2.675	2.685	2.691	-0.034	10,108	105,316	-1,067	0	400	1,679	4,656
H	Jul16	2.738	2.738	2.719	2.734	2.733	-0.034	7,731	108,876	-5,954	0	400	658	3,354
H	Aug16	2.749	2.749	2.730	2.743	2.744	-0.034	6,000	112,512	-1,529	0	400	446	1,707
H	Sep16	2.746	2.746	2.728	2.741	2.741	-0.034	6,256	101,321	-455	0	400	1,013	1,637
H	Oct16	2.778	2.778	2.753	2.765	2.767	-0.034	14,716	179,851	1,649	0	400	1,515	9,049
H	Nov16	2.853	2.856	2.842	2.853	2.856	-0.031	5,622	99,084	66	0	400	136	2,912
H	Dec16	3.014	3.014	2.995	3.000	3.010	-0.028	6,705	95,601	-4,956	0	400	1,471	2,542
H	Jan17	3.117	3.118	3.097	3.118	3.114	-0.028	9,458	94,612	-1,332	0	400	3,060	4,526
H	Feb17					3.111	-0.029	2,144	49,279	-1,663	0	400	548	168
H	Mar17					3.063	-0.025	3,386	79,317	-945	0	400	524	1,333
H	Apr17	2.860	2.860	2.860	2.860	2.866	-0.011	3,091	76,085	-3,717	0	400	750	1,440
H	May17	2.860	2.860	2.860	2.860	2.864	-0.010	1,683	43,949	-1,667	0	400	211	372
H	Jun17					2.902	-0.009	1,168	38,924	-2,457	0	400	90	210
H	Jul17	2.933	2.933	2.933	2.933	2.941	-0.009	989	40,173	-865	0	0	104	217
H	Aug17					2.956	-0.009	829	38,969	10	0	0	128	217
H	Sep17					2.949	-0.009	779	39,586	187	0	0	101	210
H	Oct17	2.955	2.955	2.955	2.955	2.974	-0.010	1,951	54,762	-462	0	0	104	1,023
H	Nov17					3.050	-0.009	735	37,368	128	0	0	251	90

EXHIBIT
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PENGAD 800-631-6989

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME AND OI TOTALS						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	[illegible] VOLUME	[illegible] VOLUME
H	Dec17					3.200	-0.013	758	47,067	-6	0	0	259	93
H	Jan18	3.300	3.300	3.298	3.300	3.296	-0.019	1,452	36,238	84	0	0	316	899
H	Feb18					3.281	-0.020	471	25,075	19	0	0	295	84
H	Mar18	3.217	3.221	3.217	3.221	3.219	-0.026	1,347	29,983	-470	0	0	316	744
H	Apr18	2.920	2.920	2.900	2.900	2.906	-0.016	1,164	32,763	355	0	0	137	720
H	May18					2.903	-0.016	485	25,157	-252	0	0	200	124
H	Jun18	2.940	2.940	2.940	2.940	2.935	-0.016	540	25,698	-160	0	0	233	120
H	Jul18					2.970	-0.016	412	27,367	-246	0	0	127	124
H	Aug18					2.983	-0.018	412	23,564	-230	0	0	127	124
H	Sep18					2.976	-0.018	402	23,758	-245	0	0	126	120
H	Oct18					3.002	-0.018	412	25,417	-144	0	0	127	124
H	Nov18					3.077	-0.018	424	25,364	-231	0	0	238	90
H	Dec18					3.234	-0.018	431	25,976	-248	0	0	239	93
H	Jan19	3.340	3.340	3.340	3.340	3.344	-0.018	182	25,682	182	0	0	120	0
H	Feb19					3.329	-0.018	148	17,353	148	0	0	120	0
H	Mar19	3.270	3.270	3.270	3.270	3.274	-0.018	213	20,296	182	0	0	120	31
H	Apr19	2.980	2.980	2.980	2.980	2.979	-0.018	60	19,255	0	0	0	0	0
H	May19					2.976	-0.018	31	17,745	0	0	0	0	0
H	Jun19					3.008	-0.018	30	16,940	30	0	0	0	0
H	Jul19					3.043	-0.018	31	17,181	0	0	0	0	0
H	Aug19					3.058	-0.018	31	17,191	13	0	0	0	0
H	Sep19					3.051	-0.018	30	17,136	30	0	0	0	0
H	Oct19					3.077	-0.018	31	19,592	31	0	0	0	0
H	Nov19					3.157	-0.018	90	17,137	50	0	0	60	0
H	Dec19					3.327	-0.018	91	18,220	51	0	0	60	0
H	Jan20					3.451	-0.017	246	11,597	75	0	0	223	0
H	Feb20					3.435	-0.017	236	9,368	71	0	0	213	0
H	Mar20					3.377	-0.017	246	11,401	75	0	0	223	0

H	Apr20					3.092	-0.017	121	10,473	-82	0	0	98	0
H	May20					3.089	-0.017	124	9,180	-7	0	0	101	0
H	Jun20					3.119	-0.017	121	8,476	-7	0	0	98	0
H	Jul20					3.151	-0.017	124	8,555	-7	0	0	101	0
H	Aug20					3.175	-0.017	124	8,512	-7	0	0	101	0
H	Sep20					3.170	-0.017	121	8,184	-7	0	0	98	0
H	Oct20					3.201	-0.017	124	8,695	-7	0	0	101	0
H	Nov20					3.281	-0.017	121	8,344	-7	0	0	98	0
H	Dec20					3.456	-0.017	124	8,908	-7	0	0	101	0
H	Jan21					3.584	-0.017	186	3,215	35	0	0	186	0
H	Feb21					3.568	-0.017	168	2,923	32	0	0	168	0
H	Mar21					3.510	-0.017	186	3,259	35	0	0	186	0
H	Apr21					3.227	-0.017	180	2,971	30	0	0	180	0
H	May21					3.222	-0.017	186	2,951	31	0	0	186	0
H	Jun21					3.252	-0.017	180	2,809	30	0	0	180	0
H	Jul21					3.289	-0.017	186	2,803	31	0	0	186	0
H	Aug21					3.319	-0.017	186	2,759	31	0	0	186	0
H	Sep21					3.318	-0.017	180	2,746	30	0	0	180	0
H	Oct21					3.354	-0.017	186	2,917	31	0	0	186	0
H	Nov21					3.434	-0.017	180	3,074	34	0	0	180	0
H	Dec21					3.609	-0.017	186	3,349	35	0	0	186	0
H	Jan22					3.737	-0.017	217	3,390	105	0	0	93	0
H	Feb22					3.721	-0.017	196	3,054	96	0	0	84	0
H	Mar22					3.663	-0.017	217	3,433	105	0	0	93	0
H	Apr22					3.380	-0.017	210	3,280	106	0	0	90	0
H	May22					3.373	-0.017	217	3,285	109	0	0	93	0
H	Jun22					3.403	-0.017	210	3,124	106	0	0	90	0
H	Jul22					3.440	-0.017	217	3,141	109	0	0	93	0

Commodity Name	Contract Month	Daily Price Range				Settle		Volume and Open Interest						
		Open	High	Low	Close	Price	Change	Total Volume	OI	Change	[illegible]	[illegible]	[illegible] Volume	[illegible] Volume
H	Aug22					3.472	-0.017	217	3,100	109	0	0	93	0
H	Sep22					3.476	-0.017	210	3,064	106	0	0	90	0
H	Oct22					3.514	-0.017	217	3,252	109	0	0	93	0
H	Nov22					3.594	-0.017	210	3,204	102	0	0	90	0
H	Dec22					3.770	-0.017	217	3,289	105	0	0	93	0
H	Jan23					3.895	-0.017	0	915	0	0	0	0	0
H	Feb23					3.877	-0.017	0	843	0	0	0	0	0
H	Mar23					3.817	-0.017	0	915	0	0	0	0	0
H	Apr23					3.532	-0.015	0	737	0	0	0	0	0
H	May23					3.523	-0.015	0	757	0	0	0	0	0
H	Jun23					3.553	-0.015	0	737	0	0	0	0	0
H	Jul23					3.591	-0.015	0	757	0	0	0	0	0
H	Aug23					3.627	-0.015	0	757	0	0	0	0	0
H	Sep23					3.637	-0.015	0	737	0	0	0	0	0
H	Oct23					3.685	-0.015	0	757	0	0	0	0	0
H	Nov23					3.765	-0.015	0	885	0	0	0	0	0
H	Dec23					3.945	-0.015	0	910	0	0	0	0	0
H	Jan24					4.067	-0.013	0	1,081	0	0	0	0	0
H	Feb24					4.047	-0.013	0	1,025	0	0	0	0	0
H	Mar24					3.987	-0.013	0	1,081	0	0	0	0	0
H	Apr24					3.692	-0.013	0	1,085	0	0	0	0	0
H	May24					3.680	-0.013	0	1,123	0	0	0	0	0
H	Jun24					3.710	-0.013	0	1,085	0	0	0	0	0
H	Jul24					3.748	-0.013	0	1,123	0	0	0	0	0
H	Aug24					3.784	-0.013	0	1,123	0	0	0	0	0
H	Sep24					3.794	-0.013	0	1,085	0	0	0	0	0
H	Oct24					3.849	-0.013	0	1,123	0	0	0	0	0
H	Nov24					3.929	-0.013	0	1,053	0	0	0	0	0

H	Dec24					4.114	-0.013	0	1,081	0	0	0	0	0
H	Jan25					4.237	-0.010	0	1,255	0	0	0	0	0
H	Feb25					4.215	-0.010	0	1,156	0	0	0	0	0
H	Mar25					4.150	-0.010	0	1,255	0	0	0	0	0
H	Apr25					3.830	-0.010	0	1,222	0	0	0	0	0
H	May25					3.815	-0.010	0	1,255	0	0	0	0	0
H	Jun25					3.853	-0.010	0	1,222	0	0	0	0	0
H	Jul25					3.901	-0.010	0	1,255	0	0	0	0	0
H	Aug25					3.945	-0.010	0	1,255	0	0	0	0	0
H	Sep25					3.960	-0.010	0	1,222	0	0	0	0	0
H	Oct25					4.020	-0.010	0	1,255	0	0	0	0	0
H	Nov25					4.113	-0.010	0	1,222	0	0	0	0	0
H	Dec25					4.313	-0.010	0	1,255	0	0	0	0	0
H	Jan26					4.433	-0.010	0	372	0	0	0	0	0
H	Feb26					4.408	-0.010	0	336	0	0	0	0	0
H	Mar26					4.338	-0.010	0	372	0	0	0	0	0
H	Apr26					3.978	-0.010	0	360	0	0	0	0	0
H	May26					3.963	-0.010	0	372	0	0	0	0	0
H	Jun26					4.001	-0.010	0	360	0	0	0	0	0
H	Jul26					4.049	-0.010	0	372	0	0	0	0	0
H	Aug26					4.093	-0.010	0	372	0	0	0	0	0
H	Sep26					4.108	-0.010	0	360	0	0	0	0	0
H	Oct26					4.168	-0.010	0	372	0	0	0	0	0
H	Nov26					4.283	-0.010	0	360	0	0	0	0	0
H	Dec26					4.508	-0.010	0	372	0	0	0	0	0
H	Jan27					4.628	-0.010	0	0	0	0	0	0	0
H	Feb27					4.603	-0.010	0	0	0	0	0	0	0
H	Mar27					4.533	-0.010	0	0	0	0	0	0	0

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME AND OI TOTALS						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
H	Apr27					4.133	-0.010	0	0	0	0	0	0	0
H	May27					4.118	-0.010	0	0	0	0	0	0	0
H	Jun27					4.156	-0.010	0	0	0	0	0	0	0
H	Jul27					4.204	-0.010	0	0	0	0	0	0	0
H	Aug27					4.248	-0.010	0	0	0	0	0	0	0
H	Sep27					4.263	-0.010	0	0	0	0	0	0	0
H	Oct27					4.323	-0.010	0	0	0	0	0	0	0
H	Nov27					4.438	-0.010	0	0	0	0	0	0	0
H	Dec27					4.663	-0.010	0	0	0	0	0	0	0
Totals for H:								**552,161**	**3,998,712**	**-22,647**	**0**	**6,000**	**60,427**	**256,712**

NOTE: The information contained in this report is compiled for the convenience of subscribers and is furnished without responsibility for accuracy and is accepted by the subscriber on the condition that errors or omissions shall not be made the basis for any claim, demand or cause of action.

NOTE: OI information is not available until the next business day.

NOTE: Volume is aggregated and representative of each Futures market strip including applicable TAS trading activity.

\# Open and Close prices reflect the first and last trade in the market and do not correlate to any opening or closing periods.

Deferred Prosecution Agreement Between the United States of America and FirstEnergy Nuclear Operating Company

The United States Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Environment and Natural Resources Division of the Department of Justice (collectively the "Department"), on behalf of the United States of America, and the FirstEnergy Nuclear Operating Company ("FENOC"), pursuant to authority granted by its Board of Directors in the form of a Board Resolution (Attachment A), hereby enter into this Deferred Prosecution Agreement (the "Agreement"). The United States acknowledges FENOC's extensive corrective actions at Davis-Besse Nuclear Power Station ("Davis-Besse"), FENOC's cooperation during investigations by the Department and the U.S. Nuclear Regulatory Commission ("NRC"), FENOC's pledge of continued cooperation, FENOC's acknowledgement of responsibility for the behavior of its employees, and its agreement to pay a monetary penalty.

Acceptance of Responsibility for Violation of Law

1. FENOC admits that the Department can prove that from September 3, 2001 through November 28, 2001, FENOC employees, acting on its behalf, knowingly made false representations to the NRC in the course of attempting to persuade the NRC that Davis-Besse was safe to operate beyond December 31, 2001, as set forth in detail in the Statement of Facts attached hereto as Attachment B (the "Statement of Facts").

2. FENOC agrees to pay a monetary penalty of $28 million. A portion of this amount may be directed to a community service project, with the agreement of both parties. None of the penalty shall be tax deductible, nor shall any of it be submitted as allowable costs in a Public Utility Commission rate-making proceeding.

EXHIBIT
OCC 6

Deferral of Prosecution

3. In consideration of FENOC's entry into this Agreement and its commitment to (a) accept and acknowledge responsibility for its conduct; (b) cooperate with the United States and the NRC as set forth in Paragraph 9; (c) make the payment specified in Paragraph 2; (d) comply with Federal criminal laws; and (e) otherwise comply with all of the terms of this Agreement, the Department, absent a material breach of this Agreement, will refrain from seeking an indictment or otherwise initiating criminal prosecution of FENOC for all conduct related to the conduct described in the attached Statement of Facts.

4. If FENOC materially breaches its obligations described herein, the Department may prosecute FENOC for any violations known to it at that time, including the conduct described in the Statement of Facts. Determination of breach shall be governed by Paragraph 12 of this Agreement.

5. FENOC agrees that in any such prosecution the Statement of Facts shall be admissible in evidence.

6. FENOC agrees to toll the running of the criminal statute of limitations during the term of this Agreement with respect to all conduct related to the conduct described in the Statement of Facts. FENOC expressly intends and hereby does waive its rights with respect to that period, including any right to make a claim premised in the statute of limitations. FENOC also waives any claim concerning pre-indictment delay, including but not limited to, speedy trial rights under the Sixth Amendment of the United States Constitution, Title 18 United States Code, Section 3161, Federal Rule of Criminal Procedure 48(b), and any applicable Local Rules for the period during which this Agreement is in effect.

7. FENOC agrees to waive its constitutional right to presentment of an indictment to a grand jury, and to allow the United States to proceed against it by filing an Information with regard to all conduct related to the conduct described in the Statement of Facts.

8. FENOC agrees that it shall not, through its attorneys, agents, or employees, make any statement, including in litigation, contradicting the Statement of Facts or its representations in this Agreement. Within 48 hours after receipt of notice by the Department of such contradictory statement, FENOC shall repudiate such statement in writing, both to the recipient and to the Department. FENOC consents to public release by the Department of such repudiation.

Cooperation with Criminal and Administrative Proceedings

9. FENOC has cooperated and will continue to cooperate with the United States and the NRC in all criminal and administrative investigations and proceedings related to the conduct described in the attached Statement of Facts. In any further inquiry, FENOC agrees that its continuing cooperation shall include the following:

9.1 FENOC will completely, truthfully and promptly disclose all information in its possession related to the matters addressed in the attached Statement of Facts about which the Department and the NRC may inquire, including all information about the activities of FENOC, present employees, former employees, consultants, and agents.

9.2 FENOC will provide the Department and NRC any information and documents of which it becomes aware that may be relevant to further criminal and administrative investigations and proceedings related to the conduct described in the Statement of Facts.

9.3 FENOC agrees to waive claims of attorney work-product protection by providing copies of witness interview summaries previously disclosed to the United States for inspection in the event that the United States brings prosecutions of individuals. By producing materials pursuant to this paragraph, FENOC does not waive the attorney-client privilege or the work-product protection, or other applicable privileges as to third parties.

10. FENOC agrees to endorse any motions filed by the United States seeking disclosure of grand jury materials to the NRC pursuant to Rule 6(e)(3)(E) for the use of administrative proceedings.

<u>Term of the Agreement</u>

11. The term of the Agreement shall commence on the date of execution and run through December 31, 2006.

<u>Breach of the Agreement</u>

12. Should the Department determine that FENOC has violated this Agreement, the Department shall provide notice to FENOC of the basis for that determination and allow FENOC 30 days to demonstrate that no breach occurred, that the breach has been cured, or that the breach does not merit further action by the Department. If the Department determines that FENOC has materially breached its obligations under the terms of this Agreement, the Department may file an Information without prior judicial approval. FENOC will have no right to seek judicial action to enjoin or otherwise prevent the filing of an Information. If criminal prosecution is initiated by the Department on the basis of a claimed material breach of this Agreement, FENOC shall not be barred from moving to dismiss the action on the ground that it has not materially breached this Agreement.

Limits of this Agreement

13. It is understood that this Agreement is binding on the Department, but specifically does not bind other Federal agencies, state or local law enforcement agencies, licensing authorities, or regulatory authorities. If requested by FENOC, the Department will bring to the attention of any such agencies the cooperation of FENOC and its compliance with its obligations under this Agreement.

Integration Clause

14. This Agreement sets forth all the terms of the Deferred Prosecution Agreement between FENOC and the United States. No modifications or additions to this Agreement shall be valid unless they are in writing and signed by the parties to this Agreement.

Greg White
United States Attorney
Northern District of Ohio

By: ______________________
Christian Stickan
Assistant United States Attorney

____
Richard Poole
Senior Trial Attorney
Environmental Crimes Section
Environment and Natural Resources Division

____
Thomas T. Ballantine
Trial Attorney
Environmental Crimes Section
Environment and Natural Resources Division

On behalf of the United States of America

By:

Gary R Leidich

Gary R. Leidich
President and Chief Nuclear Officer
FirstEnergy Nuclear Operating Company
76 South Main Street
Akron, OH 44308

WL Gardner

William L. Gardner
Morgan, Lewis & Bockius
1111 Pennsylvania Avenue, NW
Washington, D.C. 20004

On behalf of FENOC

Date of Execution: 1/18/06

Attachments:
Resolution (Attachment A)
Statement of Facts (Attachment B)

Attachment A

Resolution of the Board of Directors of FirstEnergy Nuclear Operating Company, Inc. (FENOC)

Upon motion duly made, seconded and unanimously carried by the affirmative vote of all the Directors present, the following resolutions were adopted on November 9, 2005:

WHEREAS, FENOC has been engaged in discussions with the United States Attorney's Office for the Northern District of Ohio and the Environmental Crimes Section of the Department of Justice (the "United States") in connection with an investigation being conducted by the United States into activities of FENOC employees and managers who prepared responses to an inquiry by the Nuclear Regulatory Commission;

WHEREAS, the Board of Directors of FENOC has determined that it is in the best interests of FENOC to enter into the Deferred Prosecution Agreement that the Board of Directors has reviewed with counsel representing FENOC;

NOW, THEREFORE, BE IT RESOLVED that the Board of Directors of FENOC consents to the resolution of the discussions with the United States by entering into the Deferred Prosecution Agreement in substantially the same form as reviewed by the Board of Directors and as attached hereto as Exhibit A; and

BE IT FURTHER RESOLVED that the Board of Directors of FENOC authorizes management and counsel representing FENOC to execute the Deferred Prosecution Agreement on behalf of FENOC and to take any and all other actions as may be necessary or appropriate, and to approve the forms, terms, or provisions of any agreements or other documents as may be necessary or appropriate to carry out and effectuate the purpose and intent of the foregoing.

Attachment B

In support of a deferred prosecution agreement, the FirstEnergy Nuclear Operating Company (FENOC), through its board of directors, admits that, for all times relevant to the agreement, the following facts are true:

1. FENOC operated the Davis-Besse Nuclear Power Station on the southwestern shore of Lake Erie in Ohio. FENOC held a license, issued by the Nuclear Regulatory Commission (NRC) to operate this pressurized water reactor (PWR). The Davis-Besse plant used nuclear fission to heat water to approximately six hundred degrees Fahrenheit. At that temperature, the reactor coolant water, which was sealed inside a reactor pressure vessel, reached a pressure of approximately two thousand pounds per square inch. The reactor coolant was then used to super-heat steam to drive electricity-generating turbines.

2. At Davis-Besse, reactor operators used two systems to control the rate of fission. For coarse control, they raised or lowered vertical control rods in the reactor core to absorb the neutrons that drive the fission reaction and reactor power. When the rods were fully inserted, the fission reaction became non-self-sustaining. For fine fission and reactor power control, operators also added (or removed) boric acid from the reactor coolant water. Like the control rods, the boric acid also absorbed neutrons.

3. The machinery that raised and lowered the control rods was attached to the reactor vessel head, which was removed when the reactor was being refueled. Control rod drive mechanism nozzles penetrated the dome-shaped head and the control rods were raised and lowered through those nozzles. The Davis-Besse reactor vessel head had sixty-nine nozzles. These nozzles were surrounded by a large cylindrical service structure, which was welded to the head. Because of this configuration, the only way to inspect the nozzles at Davis-Besse was by inserting a camera through inspection ports located around the bottom of the service structure.

4. After many years of service, the control rod drive mechanism nozzles could develop cracks. Although several PWR licensees had found axial nozzle cracks in the early 1990s, they were of less concern than circumferential cracks. In 2001 several PWR licensees found circumferential cracks in their reactor vessel head nozzles. Circumferential cracks also could grow around a nozzle over time. If they were not detected and repaired first, a crack could reach a critical size and allow the complete break of a nozzle. A broken nozzle could eject from the reactor head, leaving a hole through which reactor coolant could escape into the containment building. PWRs were designed to withstand such a "loss of coolant accident" and to prevent off-site radiological consequences. Nevertheless, such an event would stress a plant's safety systems.

5. For several years prior to the summer of 2001, Davis-Besse employees had failed to properly implement the plant's Boric Acid Corrosion Control and Corrective Action programs. These programs were designed to ensure that Davis-Besse employees discovered boric acid leaks, identified their sources, documented their extent, and dealt with any corrosion properly. Since 1996, some Davis-Besse employees knew that boric acid deposits were left on the reactor pressure vessel head from outage to outage. Some Davis-Besse employees also knew that the service structure surrounding the reactor

pressure vessel head impeded inspection of some of the nozzles. Inspection and cleaning steps under the Boric Acid Corrosion Control program were not performed properly during the refueling outages in 1996, 1998, and 2000. Instead, Davis-Besse engineers prepared analyses justifying operation without removing all of the boric acid.

6. In August 2001, following reports of circumferential nozzle cracks at several PWRs in the United States, the NRC issued Bulletin 2001-01. This Bulletin required the operators of PWRs, including FENOC, to provide information concerning how the potential circumferential cracking of reactor vessel head nozzles was addressed at their plants. The information each PWR operator was required to provide depended upon several factors discussed in the Bulletin, including whether there was a prior history of nozzle cracking or leaking at the plant and whether the plant's design and operating history made it more or less susceptible to nozzle cracking. With regard to Davis-Besse, FENOC was required to report on (1) the susceptibility of the plant to nozzle cracking, (2) the steps FENOC had taken to detect it, and (3) FENOC's plans for inspecting the reactor vessel head nozzles in the future. Because FENOC did not plan to inspect the Davis-Besse reactor vessel head for signs of cracking by December 31, 2001, the Bulletin required FENOC to explain how it would still meet specified regulatory requirements during the period of continued operation until the inspections were to be performed. Pursuant to section 50.9 of Title 10 of the Code of Federal Regulations, all submissions of information to the NRC, including responses to bulletins, were required to be "complete and accurate in all material respects."

7. At the time the Bulletin was issued, the next refueling outage at Davis-Besse was scheduled to begin in late March 2002. Rescheduling of the refueling outage was dependent on many factors, including delivery date of the new nuclear fuel, energy remaining in the used nuclear fuel within the reactor, replacement power costs, and availability of needed contractors and equipment. In the fall of 2001, Davis-Besse personnel had estimated that if the Company had to perform a nozzle inspection and refueling outage beginning in January 2002, then that outage would last 45 days and the Company would incur additional expenditures as compared to the scheduled 34-day refueling outage beginning at the end of March 2002. The primary contributor to the additional expenditure was higher replacement power costs during the 45-day outage starting in January.

8. In September 2001, FENOC employees at Davis-Besse responded to the Bulletin. Over the three months that followed, Davis-Besse employees submitted five "Serial Letters" to the NRC, responding to the Bulletin. These letters were numbered 2731, 2735, 2741, 2744, and 2745. In these letters, Davis-Besse employees provided technical arguments to support FENOC's position that it could continue to operate safely and in compliance with NRC regulations until March of 2002.

9. The Serial Letters included the following false statements:

9.1. A statement in Serial Letter 2731 that "inspections of the [reactor pressure vessel head] are performed ... in accordance with [Davis-Besse Nuclear Power Station] procedure NG-EN-00324, 'Boric Acid Corrosion Control Program.'" This statement was false. An inspection to determine whether boric acid was causing corrosion was one of the steps of the Boric Acid Corrosion Control Program. An engineer who inspected the reactor pressure vessel head in 1996 noted that "steps outlined in NG-EN-00324 Rev. 1 (Boric Acid Corrosion Control Program) cannot be fully implemented." The same engineer reviewed and approved Serial Letter 2731 in the Fall of 2001.

9.2. A statement in Serial Letter 2735 that "in 1996, during [the 10th refueling outage], the entire [reactor pressure vessel] head was inspected." This statement was false. In 1996, this same engineer conducted a videotaped inspection of the reactor vessel head which demonstrated that restrictions imposed by the location and size of the inspection ports prevented an inspection of the entire reactor pressure vessel head. In 2001, another engineer reviewed that 1996 videotape. Both engineers reviewed and approved Serial Letter 2735.

9.3. A statement in Serial Letter 2741 that in the spring of 2000, Davis-Besse personnel had "performed a head cleaning to allow for a quality [Reactor Pressure Vessel Head] bare metal visual inspection in April 2002." This statement was false in that the entire head had not been cleaned. The engineer who performed the head inspection in 2000 knew that substantial deposits of boric acid had been left on the head at the end of the 2000 outage. Other Davis-Besse employees received a consultant's letter in September 2001 that described substantial deposits of boric acid on the center top area of the head of the reactor. Some of these employees reviewed and approved Serial Letter 2741.

9.4 A statement in Serial Letter 2745 that, "during 10 RFO, in spring of 1996, the entire head was visible so 100% of the [control rod drive mechanism] nozzles were inspected with the exception of four nozzles in the center of the head." This statement was false for the reasons stated above, at 9.2. Serial Letter 2745 contained a probabilistic risk assessment purporting to show that Davis-Besse's core damage frequency was acceptably low, such that an immediate inspection was unnecessary. The risk assessment was based, in part, on the assumption that the 1996 inspection was as described. The engineer who performed the incomplete inspection in 1996 (described above, at 9.2) reassured the author of the probabilistic risk assessment that this assumption was correct.